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TRW Environmental Engineering Div, Redondo Beach, CA

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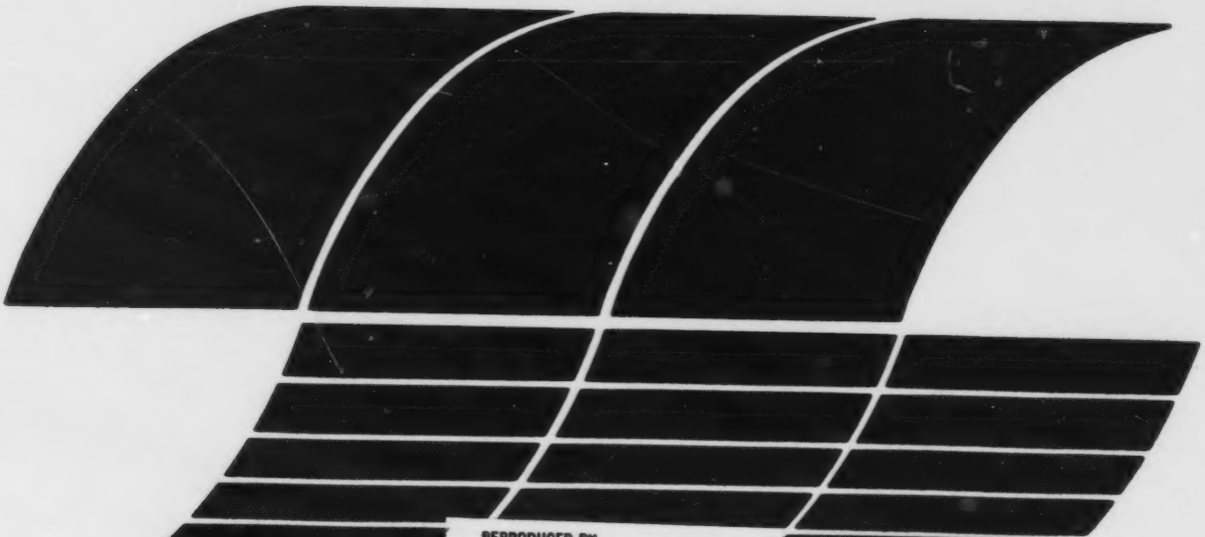

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Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG

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ABSTRACT

This Environmental Assessment Report (EAR) for the Lurgi SNG systems consists of compilation and analysis of available data on the equipment and processes which constitute the Lurgi SNG systems, the control/disposal alternatives for a media, the performance and cost of control alternatives, and the present and proposed environmental requirements. The report presents, for the use by EPA Program Offices, the best technical basis currently available for the establishment of standards for Lurgi SNG plants.

The Lurgi SNG systems were subdivided into four operations (coal preparation, coal gasification, gas purification and gas upgrading) and a number of auxiliary processes (air pollution control, raw water treatment, oxygen production, etc.), with each operation comprised of a number of processes. The data on the characteristics of input materials, products and waste streams associated with each process were presented. The pollution control alternatives for air emissions, water effluents, solid wastes, and toxic substances in an integrated facility were examined for performance, costs, energy requirements and ability to comply with current and anticipated environmental standards. The adequacy of the data was evaluated and the additional data needed to support standards development and enforcement and health and ecological effects and control technology R&D were identified.

The Lurgi gasification and a number of other processes which would be used in an SNG plant have been used commercially in other applications. Some of the data for these applications would be relevant to Lurgi SNG plants. No data are available on characteristics and treatment of certain waste streams which would be unique to Lurgi SNG plants. Programs which are recommended for filling many of the data gaps include (a) comprehensive sampling and analysis of effluents at existing Lurgi gasification plants and other industrial sites using components of the Lurgi SNG systems and (b) engineering and pilot plant studies to assess the performance of controls in Lurgi SNG service. The on-going and planned programs which may supply some of the needed data are reviewed.

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NOMENCLATURE*

Commercial-scale SNG Facility. A facility having a capacity to produce 7 x 10^6 Nm^3/d (250 x 10^6 scf/d) of substitute natural gas.

Environmental Assessment. A continuing iterative study aimed at: (a) determining comprehensive multimedia environmental loadings and environmental control costs, from the application of existing and best future definable sets of control/disposal options, to a particular set of sources, processes, or industries; and (b) comparing the nature of these loadings with existing standards, estimated multimedia environmental goals, and bioassay specifications as a basis for prioritization of problems/control needs and for judgment of environmental effectiveness.

Environmental Assessment Report. A report prepared for a specific technology, covering in depth all environmental assessment information relevant to existing or needed standards development plus a description of systems which can make up the technology, the present and proposed environmental requirements, and the best control disposal alternatives for all media.

Lurgi SNG Systems. Systems which incorporate specific Lurgi-licensed processes and various other processes which would be used in an integrated SNG facility.

Process Stream. An output stream from a process that is an input stream to another process in the technology. For example, the crude medium-Btu gas from the Lurgi gasification process is the feed (input) stream to the tar and particulate removal quench process.

Substitute Natural Gas (SNG). A manufactured gas containing about 97% methane, with a higher heating value of over 8000 Kcal/Nm^3 (900 Btu/scf), and meeting the same end-use specifications as pipeline natural gas.

Waste Stream. Confined gaseous, liquid, and solid process outputs that are sent to auxiliary processes for recovering by-products, pollution control equipment or final disposal processes; also, unconfined "fugitive" discharges of gaseous or aqueous waste and accidental discharges.

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*See Appendix A, Glossary of Environmental Assessment Terms, for additional and expanded definitions.

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1.0 SUMMARY

The recognition of the limited availability of the domestic supplies of natural gas and crude oil and the desire to reduce the country's dependence on foreign sources of energy have promoted considerable interest in this country in developing alternative domestic sources of fuel. Because of the abundance of mineable coal reserves in the U.S., the greater use of coal, directly or after conversion to substitute natural gas (SNG) or oil products, is receiving increasing emphasis. Although coal can be substituted for natural gas and petroleum for industrial and utility steam and power generation, for technical and economic reasons coal cannot replace oil and gas in applications such as residential heating and transportation. Even if coal could be substituted for oil and gas, in certain applications such substitution can present enormous pollution control problems. For example, it would be very difficult and costly to install, operate and maintain pollution control systems on large numbers of existing small and scattered residential and commercial furnaces. Coal can be converted to clean liquid and gaseous fuel which can then be conveniently substituted for natural gas and petroleum products without requiring end use equipment modification or pollution control. From the standpoint of storage and transportation, the use of SNG and coal-derived liquid fuels also offers advantages over direct coal utilization since the existing gas and oil pipeline and truck and rail distribution systems can be utilized without major modifications.

Although coal conversion processes can produce clean-burning fuels, unless properly designed and oeprated, large scale facilities for the conversion of coal to gaseous or liquid fuels can by themselves constitute major sources of environmental pollution. In response to the increasing activities related to synthetic fuels, the Environmental Protection Agency has initiated a comprehensive assessment program to evaluate the environmental impacts of synthetic fuels from coal processes having a high potential for eventual commercial application. This overall assessment program is being directed by the Fuel Process Branch of EPA's Industrial Environmental Research Laboratory, Research Triangle

Park (IERL-RTP). The primary objectives of the EPA synthetic fuels from coal program are to define the environmental effects of synthetic fuel technologies with respect to their multimedia discharge streams and their health and environmental impacts and to define control technology needs for an environmentally sound synthetic fuel industry. The effort will provide the EPA's Program Offices with the necessary technical basis for establishing standards for the industry.

The synthetic fuel technologies being addressed in the EPA program include high Btu gasification, low/medium Btu gasification and coal liquefaction. The Lurgi "dry ash" high Btu gasification system (hereafter referred to as "Lurgi" system), which is considered to have attained commercial status and has been proposed for use in the first generation commercial SNG plants in the U.S., is one of the systems being addressed in the EPA's high Btu gasification environmental assessment program. This Environmental Assessment Report (EAR) for the Lurgi SNG systems consists of compilation and analysis of all available environmental assessment information, a description of the equipment and processes which constitute the technology, a description of the control/disposal alternatives for a media, assessment of the performance and cost of control alternatives, and a description of the present and proposed environmental requirements. The report presents, for the use of all EPA Program Offices, the best technical basis available for the establishment of technology-specific standards. Since additional data on the Lurgi technology and its environmental aspects are expected to become available as a result of related on-going and planned programs, this EAR will be periodically expanded, refined and updated as needed for EPA's purposes.

1.1 OVERVIEW OF LURGI SNG SYSTEMS

1.1.1 Status of Development

The Lurgi process for coal gasification was developed during the 1930's. At present, there are eighteen operating Lurgi plants in the world producing town gas, synthesis gas (for the production of ammonia, methanol and hydrocarbons) or low Btu fuel gas. In the production of SNG using Lurgi systems, the raw Lurgi gas must be "purified" and "upgraded" to the "pipeline" quality using a number of additional processing steps. Although the required processing steps have been used commercially in other applications or have been tested on coal gases, to date no integrated commercial plant exists which incorporates all the unit processes which would be used in conjunction with the Lurgi gasifier to produce SNG. Even though there are a number of other commercially available coal gasification processes which can be used for SNG production, the Lurgi process is especially suited for SNG production as it produces a gas high in methane and hydrogen contents and requires less upgrading. Several commercial SNG plants which have been proposed for construction in the U.S. (see Section 1.1.4) all feature the Lurgi process for coal gasification.

1.1.2 Description of Lurgi SNG Systems

The conversion of coal to SNG involves the reaction of coal with steam and oxygen in a gasifier with subsequent gas processing to (a) adjust the H_2/CO ratio of the gas by the water-gas shift reaction, (b) remove acidic components and (c) catalytically convert hydrogen and carbon monoxide to methane. The chemical reactions may be approximated by the following equations:

$$\underset{\text{coal}}{6\,(C{+}H)} + \frac{5}{2}O_2 + 3\,H_2O = 4\,H_2 + 2\,CO + 3CO_2 + CH_4 \qquad \text{Lurgi gasification}$$

$$CO + H_2O = CO_2 + H_2 \qquad \text{water-gas shift}$$

$$3\,H_2 + CO = CH_4 + H_2O \qquad \text{methanation}$$

Based on the above reactions, the production of one mole of methane as a final product requires 1 mole of oxygen and 1.4 moles of steam (water) and generates 1.4 moles of CO_2 as a waste gas.

For discussion purposes, Lurgi SNG systems may be considered to be comprised of four "operations" and a number of auxiliary processes. As shown in Figure 1-1, the four operations are coal preparation, coal gasification, gas purification and gas upgrading. Each operation consists of one or more processes and produces specific outputs from certain input materials. The auxiliary processes, shown in Figure 1-2, are incidental to the main function of producing SNG and are used in connection with steam and oxygen production for gasification, recovery of products from waste streams, and pollution control.

Coal Preparation Operation. Coal pretreatment in the Lurgi systems generally consists of only crushing and screening to produce a suitably-sized coal (3 to 35 mm particles) for feeding to the gasifier. Compared to the finer coal sizes required for certain other gasification and for some combustion processes,

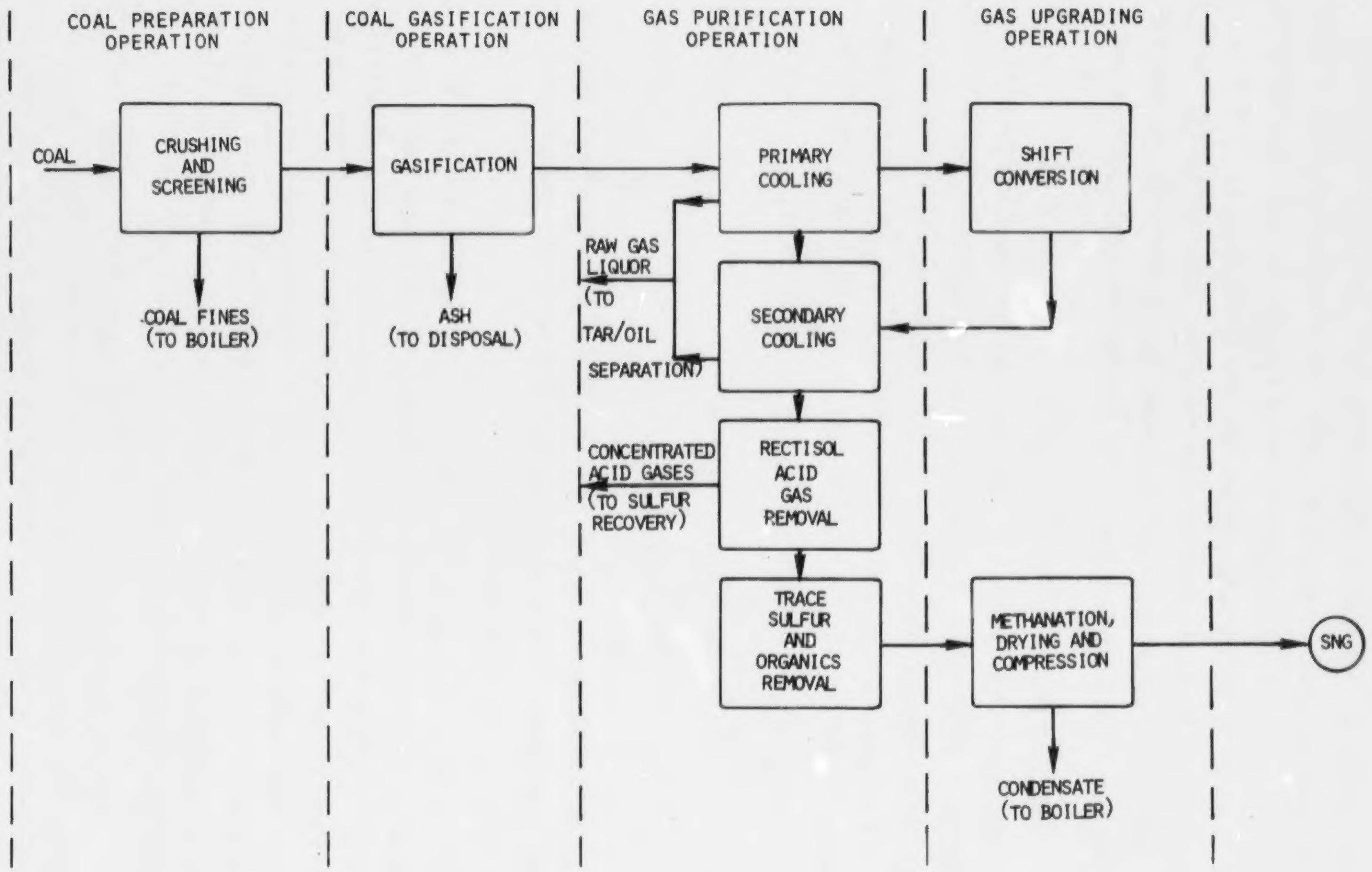
COAL PREPARATION OPERATION
COAL GASIFICATION OPERATION
GAS PURIFICATION OPERATION
GAS UPGRADING OPERATION
COAL
CRUSHING AND SCREENING
COAL FINES (TO BOILER)
GASIFICATION
ASH (TO DISPOSAL)
PRIMARY COOLING
SECONDARY COOLING
RAW GAS LIQUOR (TO TAR/OIL SEPARATION)
RECTISOL ACID GAS REMOVAL
CONCENTRATED ACID GASES (TO SULFUR RECOVERY)
TRACE SULFUR AND ORGANICS REMOVAL
SHIFT CONVERSION
METHANATION, DRYING AND COMPRESSION
CONDENSATE (TO BOILER)
SNG

Figure 1-1. Operations Comprising the Lurgi SNG Systems

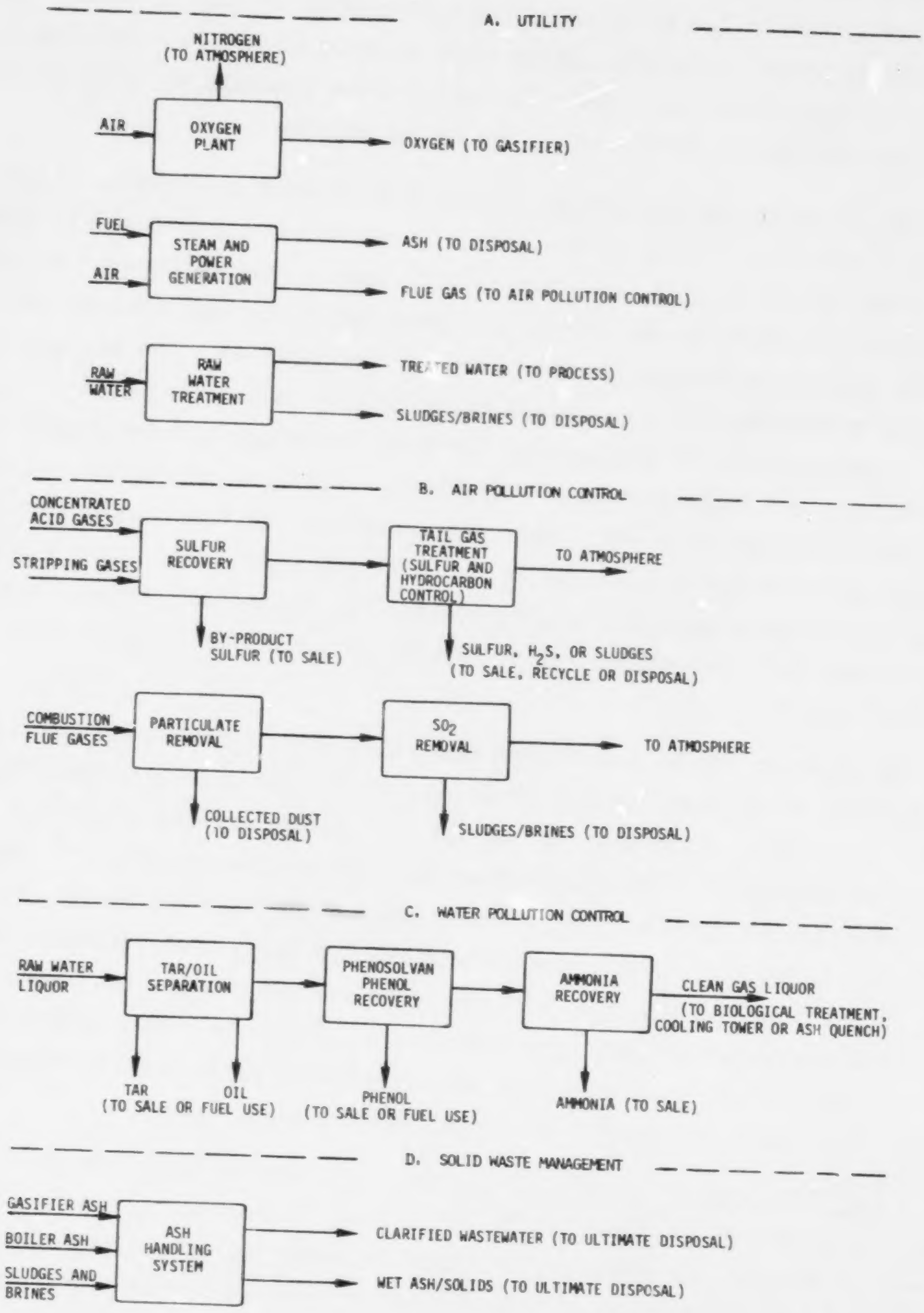
A. UTILITY
NITROGEN (TO ATMOSPHERE)
AIR
OXYGEN PLANT
OXYGEN (TO GASIFIER)
FUEL
AIR
STEAM AND POWER GENERATION
ASH (TO DISPOSAL)
FLUE GAS (TO AIR POLLUTION CONTROL)
RAW WATER
RAW WATER TREATMENT
TREATED WATER (TO PROCESS)
SLUDGES/BRINES (TO DISPOSAL)
B. AIR POLLUTION CONTROL
CONCENTRATED ACID GASES
STRIPPING GASES
SULFUR RECOVERY
BY-PRODUCT SULFUR (TO SALE)
TAIL GAS TREATMENT (SULFUR AND HYDROCARBON CONTROL)
TO ATMOSPHERE
SULFUR, H_2S, OR SLUDGES (TO SALE, RECYCLE OR DISPOSAL)
COMBUSTION FLUE GASES
PARTICULATE REMOVAL
COLLECTED DUST (TO DISPOSAL)
SO_2 REMOVAL
TO ATMOSPHERE
SLUDGES/BRINES (TO DISPOSAL)
C. WATER POLLUTION CONTROL
RAW WATER LIQUOR
TAR/OIL SEPARATION
TAR
OIL
(TO SALE OR FUEL USE)
PHENOSOLVAN PHENOL RECOVERY
PHENOL (TO SALE OR FUEL USE)
AMMONIA RECOVERY
AMMONIA (TO SALE)
CLEAN GAS LIQUOR (TO BIOLOGICAL TREATMENT, COOLING TOWER OR ASH QUENCH)
D. SOLID WASTE MANAGEMENT
GASIFIER ASH
BOILER ASH
SLUDGES AND BRINES
ASH HANDLING SYSTEM
CLARIFIED WASTEWATER (TO ULTIMATE DISPOSAL)
WET ASH/SOLIDS (TO ULTIMATE DISPOSAL)

Figure 1-2. Auxiliary Processes Associated with Lurgi SNG Systems

the larger coal size for the Lurgi process presents less handling problems from the standpoint of fugitive emissions control. Because of the special coal distribution system in the gasifier, which counteracts the caking tendency of coals, the Lurgi gasifier can handle caking coals without oxidative pretreatment to destroy caking tendencies. Coals having moisture contents up to 40 percent do not require drying before being fed to the gasifier.

Coal Gasification Operation. Figure 1-3 presents a schematic diagram of the Lurgi gasifier. The gasifier, which is operated at a pressure of about 2.5 to 3.5 MPa (25 to 35 atm), receives coal through a feed lockhopper located at the top of the gasifier and discharges ash (containing less than 5% carbon) through the ash lockhopper at the bottom of the gasifier. The hot ash is quenched with water and transported hydraulically to settling ponds for disposal. The charging of the coal to the feed lockhopper and the discharge of ash from the ash lockhopper are intermittent operations requiring pressurization/depressurization of the lockhopper chambers. The feed lockhopper is commonly pressurized with the product gas or an inert gas (e.g., CO_2). The ash lockhopper is commonly pressurized with steam. The depressurization of both lockhoppers results in the generation of a vent gas containing components of the gasifier gas.

As shown in Figure 1-3, oxygen and steam enter near the bottom and the raw product gas exits near the top of the gasifier. The countercurrent flow of solids and gases in the gasifier allows for maximum methane production and efficient heat transfer. The heat needed for gasification reactions is provided by combustion of residual carbon which takes place near the bottom of the gasifier. On a dry basis, this raw product gas typically contains about 40% H_2, 30% CO_2, 18% CO and 10% CH_4. The raw gas also contains a significant amount of unreacted steam and smaller quantities of higher molecular weight organics (e.g., tars, oils, phenols, fatty acids), reduced sulfur and nitrogen compounds (e.g., H_2S, COS, mercaptans, NH_3, HCN) and entrained dust.

Gas Purification Operation. The gas purification operation consists of gas cooling to reduce gas temperature for subsequent processing and to effect removal of condensable organics, moisture and water soluble inorganics; acid gas treatment for the removal of bulk CO_2 and reduced sulfur compounds; and removal

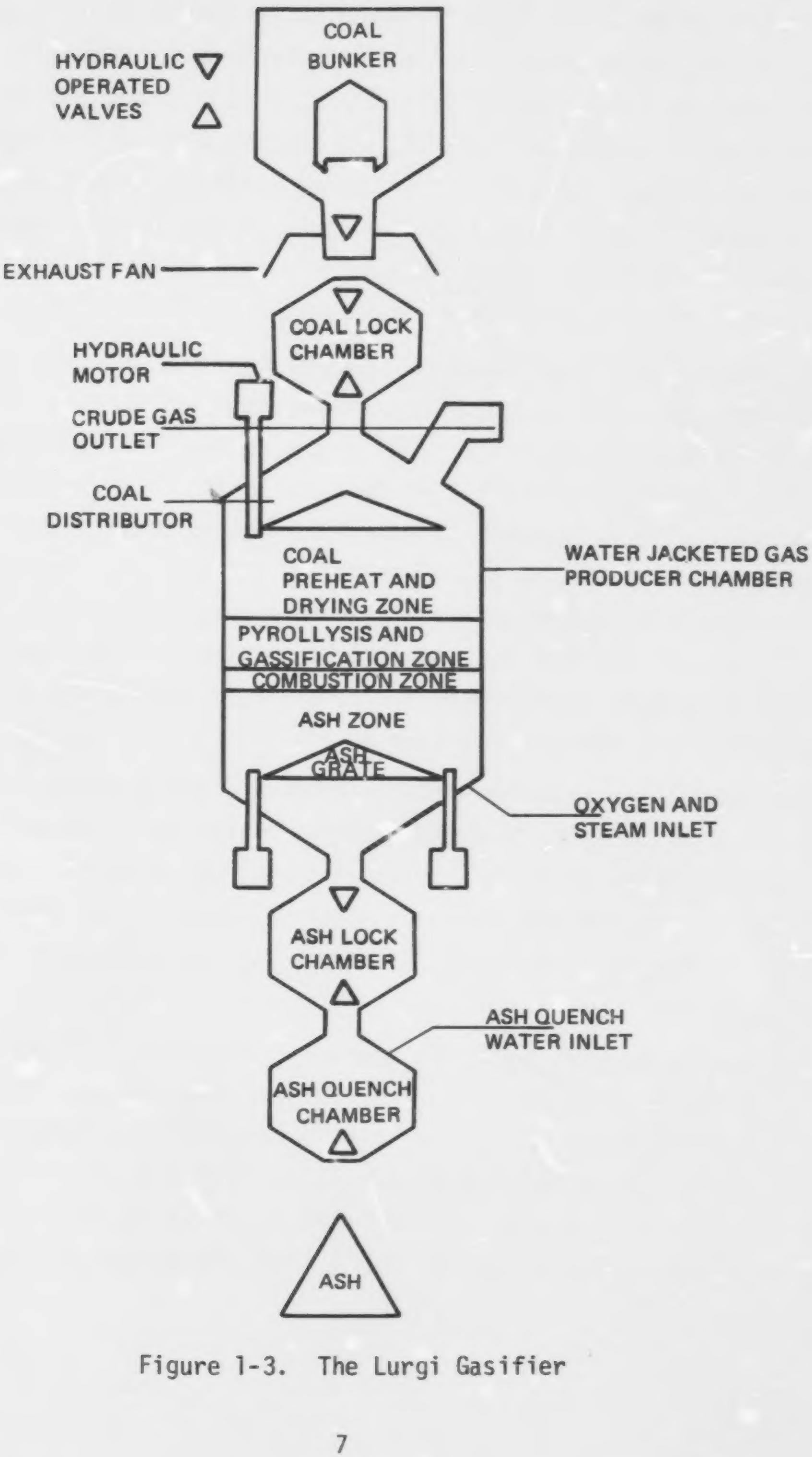
COAL
COAL BUNKER
HYDRAULIC OPERATED VALVES
EXHAUST FAN
COAL LOCK CHAMBER
HYDRAULIC MOTOR
CRUDE GAS OUTLET
COAL DISTRIBUTOR
COAL PREHEAT AND DRYING ZONE
WATER JACKETED GAS PRODUCER CHAMBER
PYROLLYSIS AND GASSIFICATION ZONE
COMBUSTION ZONE
ASH ZONE
ASH GRATE
OXYGEN AND STEAM INLET
ASH LOCK CHAMBER
ASH QUENCH WATER INLET
ASH QUENCH CHAMBER
ASH

Figure 1-3. The Lurgi Gasifier

of trace sulfur and organics using "methanation guards." Depending on the moisture and heat contents of the coal, the raw product gas exits the gasifier at a temperature of 640°K to 920°K (700°F to 1200°F). This gas must be cooled to a temperature of about 272°K (30°F) prior to treatment for acid gas removal. The gas cooling, which consists of quenching with water (recycled gas liquor) and heat recovery in waste heat boilers, is carried out in two stages. Medium pressure steam is produced in the primary coolers whereas low pressure steam is produced in secondary coolers. After primary cooling, a portion of the gas passes through the shift conversion unit (see below) before secondary cooling. The condensates produced during gas cooling (referred to as "raw gas liquor") are collected and sent to tar/oil separation units for by-product recovery.

The removal of sulfur compounds and CO_2 from the gas is necessary to prevent catalyst poisoning in the subsequent methanation step and to obtain a high heating value gas, respectively. The Lurgi-licensed Rectisol process is used in Lurgi systems for the removal of the bulk of the sulfur compounds and CO_2. The process uses cold methanol to absorb acid gases under pressure. The solvent is regenerated by step-wise depressurization and heating. Concentrated acid gases from solvent regeneration are sent to the sulfur recovery plant. Total sulfur levels of less than 0.1 ppmv can be obtained in the treated Rectisol gas. The Rectisol process also enables the recovery of naphtha and affects removal of moisture and trace constituents such as HCN.

The product gas from the Rectisol process contains traces of sulfur which must be removed in order to avoid catalyst poisoning in the methanation step. This is accomplished by use of "methanation guards" ahead of the methanator. Methanation guards are beds of solid absorbent (e.g., ZnO) which removes sulfur compounds by chemical reactions. The exhausted bed is usually discarded rather than regenerated.

Gas Upgrading Operation. Gas upgrading consists of shift, methanation and drying. An H_2:CO ratio of 3:1 is required for methanation. To obtain this ratio, a portion of the gas exiting the primary cooler is catalytically shifted and then recombined, after secondary cooling, with the "unshifted" gas. Methanation involves the catalytic reaction of H_2 and CO to form methane and water. The large amount of heat released in the methanation step is recovered via steam production. The gas is dehydrated by cooling to condense moisture and by use of a dehydrating solvent (usually glycol) or molecular sieves. Cobalt molybdate and nickel-based materials are used as shift and methanation catalysts, respectively. The shift catalyst is regenerated by air oxidation which destroys the carbon deposits formed on the catalyst. The methanation catalyst is "decommissioned" (by controlled air oxidation) prior to removal from the system. Catalyst regeneration and decommissioning produce off-gases requiring control. Both the spent shift and methanation catalysts are solid wastes requiring treatment for resource recovery and/or disposal.

Auxiliary Processes. Auxiliary processes at an integrated commercial Lurgi SNG plant fall into two categories: pollution control and utilities. Except for a number of Lurgi-licensed pollution control processes and sulfur recovery/tail gas treatment processes, most processes are not unique to Lurgi plants or present any special problems which would be unique to such plants. The Lurgi-licensed pollution control processes for use in Lurgi SNG plants are gas liquor treatment for tar and oil separation, Phenosolvan process for phenol recovery and Linz-Lurgi process for dissolved gases removal. A brief description of these processes and of sulfur recovery/tail gas treatment and onsite steam and power generation (which can potentially present the largest emission source at a Lurgi SNG plant) follows.

The Lurgi gas liquor treatment process operates on a gas flotation principle whereby the reduction in the pressure on the gas liquor causes the release of gas bubbles, thereby enhancing the gravity separation of tars and oils which are recovered as by-products. The "clean" gas liquor from the tar/oil recovery process is treated by the Phenosolvan process for phenol removal. In this process, the phenols are removed from the wastewater by extraction with an organic solvent; the solvent is regenerated by distillation which also results in the recovery of crude phenols as a by-product. Although several stripping processes are available for the recovery of ammonia and H_2S from dephenolized gas liquor, some Lurgi plants feature the Linz-Lurgi process which provides for steam stripping of CO_2 and H_2S at a controlled gas liquor pH of about 5.0 followed by ammonia stripping in an ammonia stripper. Ammonia is recovered as a 25% gaseous solution.

Concentrated acid gases from the Rectisol acid gas treatment process and the flue gases from onsite steam and power generation are the two most voluminous and significant gaseous waste streams in a Lurgi SNG plant. Depending on the sulfur content of the concentrated acid gases, treatment may consist of sulfur recovery in a Claus unit followed by tail gas sulfur removal or in a Stretford unit followed by incineration. The Claus process is a dry high temperature process in which H_2S is catalytically reacted with SO_2 (produced by air oxidation of a portion of the H_2S) to form elemental sulfur. Although the Claus process is most applicable to very concentrated acid gas streams, it has been used on gases containing as little as 5% H_2S. To maintain a high efficiency, more dilute H_2S feed gases must be concentrated using commercially available processes such as ADIP prior to Claus treatment. Since the Claus process operates at a high temperature, it also achieves partial destruction of hydrocarbons, COS and CS_2. Claus tail gases typically contain about 10,000 ppm total sulfur, thus requiring tail gas treatment for pollution control using processes such as Wellman-Lord and Beavon. In contrast to Claus, the Stretford process, which employs liquid phase oxidation of H_2S to elemental sulfur, can handle dilute H_2S feed gases and can achieve very low levels of H_2S (less than 10 ppm) in the product gas. The process, however, does not remove hydrocarbons, COS or CS_2 which require incineration or tail gas treatment.

When coal or gasification by-products (tars, oils, phenols or naphtha) are used as fuel for onsite steam and power generation, the combustion flue gases can be potentially the largest source of SO_x, particulates and NO_x emissions at a Lurgi SNG plant. For this reason, control of combustion flue gases is a very important part of any overall air pollution control plan at a Lurgi SNG plant. As with flue gases from coal-fired utility and industrial boilers, these emissions can be controlled using electrostatic precipitators and fabric filters to remove particulates, flue gas desulfurization systems (e.g., lime/limestone scrubbing or Wellman-Lord process) for SO_x removal and combustion modification for NO_x control.

1.1.3 Process Energy and Cost Considerations

Although through gasification an environmentally desirable fuel can be produced from our abundant supply of coal which would be substituable for natural gas in most applications, it must be recognized that a significant energy penalty and a high cost are associated with the conversion of coal to SNG. Based on the proposed designs for commercial Lurgi SNG plants, only about 60% of the energy in the total coal input to the plant is recovered as SNG. Of the other 40%, about 5% is in the form of by-products (assuming that the by-products are not used as part of the fuel for onsite power/steam generation), about 10% is consumed in connection with gas purification, gas upgrading and pollution control, and the other 25% is a thermal loss incurred in the gasifier and gas coolers. Although this energy recovery efficiency appears to be low, when end use efficiencies are taken into account the overall energy recovery from coal via SNG production is comparable to or higher than those associated with other means of coal utilization. The energy recovery efficiency is about 35% for coal-fired utility boilers producing electricity. However, when used in space heating applications, the overall energy recovery efficiencies for coal-to-SNG-to-heat and coal-to-electricity-to-heat routes are about 36% and 32%, respectively.

Recent cost estimates for commercial Lurgi SNG plants indicate that a 7 x 10^6 Nm^3/d (250 x 10^6 scf/d) facility will require a capital investment of as much as \$2 billion (1978 dollars) and an annual operating cost of about \$300 million. These costs would translate into a gas selling price of $\$20/10^6$ kcal ($\$5/10^6$ Btu) at the plant, a price well above the current price of even the most expensive intrastate natural gas at the wellhead (about $\$10/10^6$ kcal or $\$2.50/10^6$ Btu). An approximate breakdown of the capital cost for a commercial Lurgi SNG plant is shown in Figure 1-4. As shown in the figure, coal preparation, gasification, quench and shift collectively account for about 30% of the total plant investment. Utilities and general facilities account for about an additional 30%. Capital investment for pollution control is estimated at about 5% of the total. Operating costs associated with pollution control can account for approximately 10% of the total operating costs.

1.1.4 Commercial Prospects for a Lurgi SNG Industry

Although the Lurgi technology for the production of SNG from coal is considered technically viable, and several commercial Lurgi SNG plants have been proposed for construction in the U.S., the actual construction of such plants has been stalled primarily by regulatory and economic uncertainties. Although the Federal Energy Regulatory Commission (FERC) has the authority to regulate

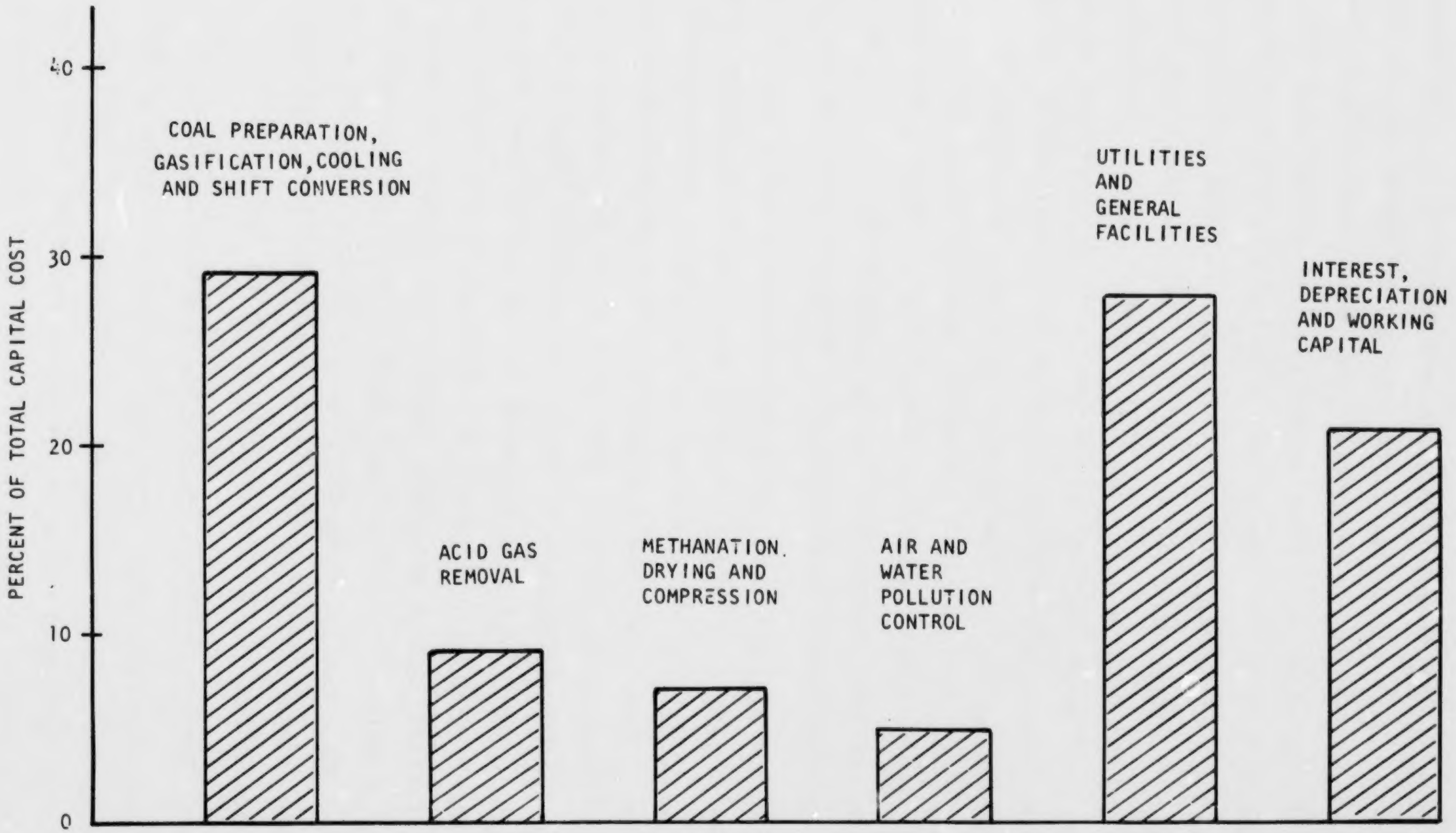

Figure 1-4. Breakdown of Capital Investment Cost for a Commercial Lurgi SNG Plant

the price of SNG in interstate commerce, no such action has been taken to date and it is currently unclear what the selling price and mechanism for cost recovery will be approved by FERC. Because of the high capital and operating costs and the anticipated risks associated with the construction of the first Lurgi SNG plants, developers have been unable to secure the necessary financial commitment from private or government sources for the construction of such plants. The development of a viable commercial SNG industry (using Lurgi or any other gasification technology) would require a substantial commitment of raw material (water, coal, land), manufacturing capacity (e.g., for steel fabrication) and labor resources. Such a large commitment of resources would impact other industrial developments, create a number of socioeconomic problems and may arouse significant opposition from environmental groups and special interest groups.

1.2 WASTE STREAMS AND POLLUTANTS OF MAJOR CONCERN

Table 1-1 lists the key process and waste streams and pollutants/parameters of major concern in these streams. (The applicable control technologies listed in the table are discussed in Section 1.3.) A number of streams shown in the table (e.g., tars and oils, clean gas liquor) are confined within the plant or transported or used in other locations in closed systems. The hazards associated with these streams are generally related to occupational exposure or stem from accidents and spills during handling and transportation. Some of the streams are relatively small in volume (e.g., lockhopper vent gases) or occur infrequently (e.g., transient gases). Waste streams such as combustion flue gases from on-site steam and power generation are not unique to Lurgi SNG plants and do not present new environmental problems. Because many of the streams listed in Table 1-1 have not been well characterized (in most cases due to the current non-existence of SNG plants), especially from the standpoint of toxicity and trace constituents (see Section 1.4), the nature and extent of the potential hazards associated with these streams are not known.

With respect to volume and concentration of potential air pollutants, two gaseous waste streams of major environmental concern in a Lurgi SNG plant are concentrated acid gases from the Rectisol process and flue gases from onsite combustion of coal or by-products for steam and power generation. The volumes of

TABLE 1-1. MAJOR POLLUTANTS/PARAMETERS OF CONCERN IN KEY PROCESS AND WASTE STREAMS AND APPLICABLE CONTROL TECHNOLOGIES

Product, By-Product or Waste Stream	Source	Constituents/Parameters of Major Concern	Applicable Control Technology
Product/By-Product			
SNG	Final product	CO, $Ni(CO)_4$	In-plant process control
Tars, oils and phenols	Raw gas liquor treatment	Aromatic hydrocarbons, polycyclic organics, phenols, trace elements, toxic properties	Prevention of leaks/spills, use of worker protection measures, combustion for steam/power generation, injection into gasifier
Naphtha	Rectisol process	Aromatic hydrocarbons and polycyclic organics, toxic properties	Prevention of leaks/spills, use of worker protection measures, combustion for steam/power generation
Ammonia	Gas liquor treatment	Ammonia, trace contaminants	Prevention of leaks/spills, use of worker protection measures
Gaseous Waste Streams			
Lockhopper and transient waste gases	Gasifier	Sulfur and nitrogen compounds, CO, organics, particulates, trace elements, toxic properties	Incineration and particulate control, proper operating procedures
Concentrated acid gases	Rectisol process	H_2S, COS, CS_2, HCN, CO, hydrocarbons, mercaptans	Sulfur recovery, incineration/FGD
Sulfur recovery tail gas	Sulfur recovery plant	Same as for concentrated acid gases	Catalytic reduction and H_2S recycle, incineration, incineration/FGD
Catalyst decommissioning/ regeneration off-gases	Decommissioning/ regeneration of shift and methanation catalysts	Metal carbonyls, CO, sulfur compounds, organics, toxic properties	Incineration and particulate control
Combustion flue gases	Onsite steam and power generation	SO_2, NO_x, particulates, trace elements	Electrostatic precipitators, fabric filters, FGD systems and combustion modification
Aqueous Waste Streams			
Ash quench slurry	Quenching of gasifier ash	Dissolved and suspended solids, alkalinity, trace elements, components of the clean gas liquor used for quenching (see below)	Gravity separation, dissolved solids removal, disposal of solids in containment ponds/ landfills
Clean gas liquor	Ammonia recovery	Sulfide, thiocyanate, ammonia, dissolved organics, BOD, COD, pH, biotreatability	Biooxidation, use as cooling tower or quench water makeup
Waste sorbents and reagents	Pollution control units	Sulfur compounds, trace elements, dissolved and suspended solids and other constituents (depending on specific source)	Resource recovery, oxidation, dissolved solids removal, use as ash quench
Combined plant effluent	Ash quench, FGD, and raw water treatment	Dissolved and suspended solids, COD, BOD, alkalinity, trace constituents, toxic properties	Forced or solar evaporation
Solid Waste Streams			
Gasifier and boiler ash	Ash quench systems	Leachability, compactability, leachate characteristics (including trace elements and organic contents and toxic properties)	Disposal in lined landfills and ponds, return to mines
Spent catalysts	Shift and methanation	Metallic compounds, accumulated trace elements/ organics, leachability and leachate characteristics	Resource recovery, encapsulation, disposal in lined landfills, return to mines
Tarry/oily and bio-sludges	By-product storage and wastewater treatment	Aromatic and polycyclic hydrocarbons, trace elements, toxic properties	Energy recovery, disposal in lined landfills, return to mines
Inorganic solids and sludges	FGD systems, miscellaneous sources	Same as for gasifier and boiler ash	Same as for gasifier ash

these streams are about 1.4 and 3 times the volume of the product SNG, respectively. Pollutants of major concern in the concentrated acid gases are reduced sulfur compounds, hydrogen cyanide and hydrocarbons. Essentially all the sulfur originally present in the coal fed to the gasifier appears in the concentrated acid gases. (Coal pretreatment, when employed, may also release some of the sulfur contained in the coal, thus requiring controls for the pretreatment wastes.) Except for a very lean H_2S acid gas stream from the Rectisol process, which would require only incineration before atmospheric discharge, the acid gases are treated for sulfur recovery/removal (and hydrocarbon removal) prior to final emission. The flue gases from onsite coal combustion at a 7×10^6 Nm^3/d (250×10^6 scf/d) plant are equivalent in volume to that produced by a 250-MW coal-burning power plant.

As currently envisioned, commercial Lurgi SNG plants constructed in the U.S. will have zero discharge to receiving waters. The wastewaters from these plants will be contained in ponds and disposed of by solar evaporation or reclaimed for process use. Accordingly, aqueous waste streams in these plants would be considered internal process streams and not effluents. Providing for suitable methods for wastewater containment/treatment and for disposal of residues resulting from such treatment is the major problem of environmental concern. The characteristics of the residues resulting from the treatment of combined plant effluents are determined by the constituents in the three major internal aqueous waste streams, namely ash quench slurry, clean gas liquor and waste solvents and reagents. The organic compounds in the residue originate in the clean gas liquor while the major inorganic constituents and trace elements originate in the ash quench slurry.

Wet ash from the gasifier and boiler ash quench systems is the largest volume solid waste stream in an SNG plant. A 7×10^6 Nm^3/d (250×10^6 scf/d) Lurgi SNG plant using a coal containing 15% ash and employing onsite coal combustion for steam and power generation would be expected to generate an estimated 4900 tonne/d (5400 ton/d) of wet ash (about 20% moisture content). As with the utility industry, the disposal of such a voluminous quantity of waste can create a major solid waste management problem. These wastes, which are usually disposed of in ponds and landfills, contain constituents which may be mobilized via leaching in the disposal site. Such constituents may be the soluble inorganic components of the ash or organic or inorganic materials which become associated with the ash when process waters (e.g., clean gas liquor) are used for ash quenching. Although of relatively very small quantity, the spent catalysts are of special concern due to their content of potentially toxic metals (Ni, Mo, Co) and coal-derived organic compounds and trace elements. Except for sludge from FGD systems, the inorganic solids and sludges and the tarry/oily and biosludges are generated in relatively small quantities.

1.3 STATUS OF ENVIRONMENTAL PROTECTION ALTERNATIVES

The control technologies for the management of waste streams of major environmental concern in a Lurgi SNG plant are listed in Table 1-1. These technologies fall into two categories: (1) those which have been used on waste streams from Lurgi and other gasification plants in other countries and (2) those which have been used on similar waste streams in other industries. Most of the technologies in both categories are considered to be commercial, although large uncertainties exist relating to their performance and cost in application to waste streams in a commercial Lurgi SNG plant. These uncertainties are due to (a) the lack of data on applications on waste streams at foreign facilities and (b) the differences in waste stream characteristics. Examples of the technologies in the first category are injection of organic by-products into the gasifier; recovery of sulfur from concentrated acid gases using the Claus process; gravity separation of ash quench slurry and disposal of gasifier and boiler ash in ponds. Examples of the technologies in the second category are combustion of tars for steam/power production in the coke industry, recovery of sulfur from coke oven gases using the Stretford process, treatment of sulfur recovery tail gases in refineries using the Beavon and Wellman-Lord processes, biological oxidation of petroleum refinery and coke plant wastewaters, and disposal of utility ash and FGD sludges in ponds. Some of the technologies in the second category (e.g., FGD and particulate control systems for flue gases) have been widely used in almost identical applications in other industries and their performance and costs are reasonably well defined. For other technologies, the available cost and performance data are for other applications (e.g., use Beavon sulfur recovery tail gas treatment in refineries) and must be verified on actual or simulated SNG wastes.

As indicated in Table 1-1, there is generally more than one control technology for application to a specific waste stream. In most cases, the definition of the best or the most cost-effective control technology requires more detailed data on characteristics and on the capabilities of control technology than currently are available. Furthermore, the selection of specific controls for most individual streams in an integrated SNG plant cannot be made independent of the selection of other controls and overall environmental management plan for the facility. The selection of these controls and the management plan are influenced by (and in turn influence) the design of the facility. Because of the lack of detailed information on waste characteristics and control technology capabilities, it is not possible at this time to identify and compare all the possible options for the control of air, water and solid waste management in a commercial Lurgi SNG plant. Preliminary examinations have been made of selected sulfur controls for concentrated acid gases and flue gases, the two most important gaseous waste streams in an integrated plant. These examinations indicate that: (a) the lowest overall sulfur emissions (but not the lowest cost) can be obtained through the use of the Stretford process for the treatment of concentrated acid gases and the use of desulfurized fuel gas for steam and power generation; (b) the lowest overall cost (but not the lowest emissions) can be achieved via use of the Claus process with tail gas treatment for sulfur recovery from H_2S-rich acid gases, the Stretford process for sulfur recovery from H_2S-lean acid gases and FGD systems on flue gases from coal-fired boilers; and (c) incineration of concentrated acid gases in the utility boilers and use of FGD systems on the combined flue gases does not appear to be competitive with other options both in terms of costs and sulfur emissions levels.

1.4 DATA NEEDS AND RECOMMENDATIONS

The U.S. EPA has the responsibility for developing guidelines and standards and promulgating and enforcing regulations to achieve national environmental goals. The development of sound and enforceable standards for an industrial source category requires an adequate technical data base which would include reasonably detailed information on the characteristics of products and wastes, capabilities and costs of control technologies, and the effects of pollutants on human health and the environment.

At the present time there are no specific EPA standards for Lurgi SNG plants. Under the mandate of several existing laws (see Table 1-2), however, such standards may have to be developed in the near future. As a result of EPA data gathering and assessment programs and activities by process developers and

TABLE 1-2. STATUS OF EPA REGULATIONS UNDER EXISTING LAWS WHICH WOULD AFFECT LURGI SNG PLANTS

Law	Key Pertinent Regulatory Features	Status of Regulations
The Clean Air Act Amendments (PL 91-604)	• Development of New Source Performance Standards (NSPS) for industrial source categories • Preconstruction review of major emission sources to prevent significant deterioration of ambient air quality ("PSD" regulations) • Establishment of emission standards for hazardous air pollutants from stationary sources	• No NSPS have been developed for Lurgi plants • Emissions guidelines have been developed for Lurgi SNG to assist states and EPA Regional Offices in setting plant-specific standards • "PSD" requirements for SO_2 and particulates and regional air quality classification have been completed • Hazardous emissions standards have been set for asbestos, mercury, beryllium and vinyl chloride
Federal Water Pollution Control Act Amendments (PL 92-500); Clean Water Act Amendments (PL 95-217)	• Establish effluent limitations and guidelines covering conventional, toxic and nonconventional pollutants for new industrial sources discharging into navigable waters	• No effluent guidelines have been developed for Lurgi plants • A list of 129 toxic substances/classes of toxic substances have been developed for regulation • A list of industries categories for which standards will have to be developed has been developed. The list does not currently include Lurgi SNG plants
Resource Conservation and Recovery Act (RCRA) (PL 94-580)	• Develop criteria for identification of hazardous wastes • Develop regulations for handling, transportation, storage, treatment and disposal of hazardous wastes	• Identification criteria and hazardous waste handling, storage, treatment and disposal regulations have been proposed • Proposal has been made to classify coal ash and FGD sludges as "special wastes" and not as "hazardous wastes"
Toxic Substances Control Act (PL 94-469)	• Promulgate regulations for the manufacture, processing and distribution in commerce, use or disposal of substances or mixture of substances presenting unreasonable risk to health and environment • Issue regulations on testing, premarket notification and reporting/retention of information	• A priority listing of chemicals for toxicity testing has been developed • No substance-specific regulations have yet been developed

other government agencies, a considerable volume of data currently exists on the environmental aspects of the Lurgi SNG technology. A large number of gaps, however, exist in these data which would have to be filled in order to establish the data base needed for the development of standards and for defining health effects and control technology R&D needs. These data gaps fall into two categories: (1) the total non-existence or unavailability of data, and (2) the data which are available lack comprehensiveness or have been obtained under conditions significantly different than those anticipated in an integrated commercial Lurgi SNG plant in the U.S.

The major waste streams in a Lurgi SNG plant and the applicable control technologies were presented in Table 1-1. Although considerable characterization data are available for some of these streams (e.g., concentrated acid gases and clean gas liquor), such data generally cover only the major constituents and gross parameters (e.g., H_2S content for the acid gases or COD concentration for the gas liquor) and have been obtained in foreign Lurgi facilities using coals and process designs which would not necessarily represent those in a U.S. plant. Almost totally lacking for all streams are data on the type and concentration of organic substances, trace elements, and hazardous and ecological properties. Such data would be required to identify those streams/constituents which have to be regulated under the provisions of the laws listed in Table 1-2. For some streams no data are available on quantities and characteristics primarily due to the nonexistence of such streams (e.g., combined plant effluent) in existing gasification plants or the proprietary nature of the data (if any such data indeed exists).

Of the control technologies listed in Table 1-1, only a few (e.g., the Phenosolvan process for phenol recovery and flaring of transient gases) have actually been used on Lurgi gasification wastes. Very little performance and cost data, however, are available for these applications. Some control technologies have been used in similar applications in other industries and some data are available on cost and performance of such applications. The data from these other applications cannot be generally extrapolated to Lurgi SNG service due to differences in process design and waste stream characteristics. The Stretford process, for example, has been used for the treatment of coke oven acid gases which have significantly lower levels of CO_2 than Lurgi acid gases. Biological treatment has been successfully used in the treatment of refinery wastes and considerable cost and performance data are available for such applications. Since gasification waste streams are expected to differ from refinery wastewaters in terms of the nature of organic constituents and presence and concentration of toxic components, the applicability and cost of biological treatment of gasification wastewaters are not known.

Some of the data needed to support standards development and enforcement activities would have to be generated through multimedia sampling and analysis and through R&D programs in the areas of health and ecological effects and control technology development. Through such programs, reliable and comprehensive data must be generated on products and waste characteristics, performance and cost of control technologies and health and ecological effects of wastes and products/by-products. Implementation of programs in the following areas is expected to generate some of the data needed to support the development and enforcement of standards for Lurgi SNG plants:

- Incorporation of additional data in this "Environmental Assessment Report" as they become available as a result of on-going and future sampling and analysis programs and engineering studies.
- "Phased-Level" comprehensive chemical/biological testing of process effluents at existing Lurgi coal gasification plants and at other industrial sites using components of Lurgi SNG systems.
- Support studies to assess the health and ecological effects of Lurgi SNG products and waste streams. Such studies should address the presence of toxic substances and synergistic effects, bioaccumulability, mechanism and rate of transport, and fate of pollutants in the environment.
- Engineering and pilot and bench-scale studies to determine the effectiveness and cost of various control technologies as applied to Lurgi waste streams.
- Miscellaneous support activities including development of sampling and analysis protocols and standardized environmental assessment methodologies.

A number of programs are currently on-going or are planned which contain certain elements of the above recommended program areas. The most important of these programs, the result of which will be incorporated in any revision to this document, is the EPA-sponsored multimedia environmental sampling and analysis effort currently under way at the Kosovo Lurgi plant in Yugoslavia. This program is the first multimedia environmental sampling and analysis effort undertaken at a commercial synthetic fuels plant.

1.5 ISSUES AND AREAS OF CONCERN FOR PROGRAM OFFICES

The gaps in the available data which must be filled in order to provide the necessary basis for establishing technically sound and enforceable regulations for Lurgi SNG plants were identified in the previous section. The identified data gaps reflect the needs and the requirements for various EPA Program Offices for establishing such standards. Some specific needs and requirements for certain of the EPA Program Offices are listed below.

Office of Air Quality Planning and Standards
Emission Standards and Engineering Division

In the absence of actual plant operating data, the following information would be desired:

- Comparative data on hydrocarbon control methods (e.g., use of ADIP process vs. incineration of offgases) and fate of hydrocarbons in various offgases
- Fate of and control methods for organic sulfur
- Operating data for the Stretford process (e.g., the unit at SASOL) handling gases containing high CO_2 concentrations

Office of Water Planning and Standards
Effluent Guidelines Division

- Characterization of Lurgi SNG plant wastewaters, i.e., flows, quantities and composition (especially, the presence and concentrations of priority pollutants)
- Assessment of wastewater pollution control technologies, specifically:
    - applicability of control technologies used in other industries
    - composition of residual dissolved constituents
    - in-plant methods for wastewater volume and concentration reduction
- Development of suitable analytical methods for characterization of SNG plant wastewaters and for assessment of data and statistical soundness of proposed sampling and analysis (e.g., for evaluating proposed DOE programs)

Office of Solid Waste
Hazardous Waste Management Division

- Characterization of the solid wastes generated at Lurgi SNG plants to determine whether such wastes should be classified as hazardous and hence whether or not subject to regulations pursuant to RCRA

- Waste characterization data, using the "Toxic Extraction Procedure" and/or long term leaching tests (e.g., using lysimeters), are needed to assess potential for the contamination of surface and groundwaters via leachate from landfills and runoff from waste storage/disposal sites

Office of Toxic Substances
Testing and Evaluation Division

- Identification of all toxic substances (in particular trace metals and organics) in Lurgi SNG products/byproducts which may come in contact with the general public
- Better definition of specific hazards associated with various substances of concern
- Detailed characterization data on products, byproducts and wastes to enable material balance calculations for various toxic substances

Office of Radiation Programs
Environmental Analysis Division

- Determination of radioactive waste emissions, as air pollutants (in waste gases and fugitive emissions) and as solid waste
- Sampling and analysis of waste gases, solid wastes and feed (coal/supplementary fuel) for radioactivity (including radon emission) to enable material balance calculations

2.0 PROCESS DESCRIPTION OF LURGI GASIFICATION SYSTEMS

For the purpose of this report, Lurgi systems for the production of SNG are defined as systems which incorporate specific Lurgi-licensed processes and various other processes which would be used in an integrated commercial SNG facility. (See Section 2.2 for a discussion of processes which comprise the Lurgi systems.) This chapter presents a technical overview of Lurgi systems and includes information relating to the status of commercial Lurgi SNG projects, input materials, products and byproducts, energy efficiencies, costs, and factors affecting the siting of plants and the development of an SNG industry. A description of processes which constitute coal preparation, gasification, gas purification and gas upgrading operations and of pollution control and other auxiliary processes is provided. This description emphasizes waste generation and waste stream characteristics, known environmental problems and process areas of current environmental concern.

2.1 TECHNICAL OVERVIEW OF LURGI SYSTEMS

2.1.1 Status of Development

The dry ash Lurgi gasification process has been commercially available since 1940. The original version of the technology was demonstrated by A. G. Saechsische Werke in 1930 in a pilot plant at Hirschfelds, Germany(1). The pilot scale work provided the basis for subsequent development of the "Lurgi Pressure Gasification Process" by Lurgi Mineralöltechnik GmbH of West Germany.* To date, 18 plants located throughout the world have used the West German process for the production of town gas, synthesis gas or low-Btu fuel. The newest and largest of these facilities is the SASOL plant in Sasolburg, South Africa,

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*A parallel development of the Lurgi process has been carried out by the German Democratic Republic (East Germany) since World War II and several commercial plants using the East German Technology currently exist in East European countries. Examples of these commercial plants are the Gaskombinant Schwarze Pumpe in East Germany and the Kosovo Kombinant plant in Pristina, Yugoslavia.

TABLE 2-1. DRY ASH LURGI COMMERCIAL INSTALLATIONS USING THE WEST GERMAN LURGI TECHNOLOGY(1)

Plant No.	Location	Year	Type of Coal	Gasifier I.D.	Capacity (MMSCFD)	No. of Gasifiers
1	Bohlen, Central Germany	1940	Lignite	8'6"	9.0	5
2	Bohlen, Central Germany	1943	Lignite	8'6"	10.0	5
3	Most, CSSR	1944	Lignite	8'6"	7.5	3
4	Zaluzi-Most, CSSR	1949	Lignite	8'6"	9.0	3
5	Sasolburg, South Africa	1954	Subbituminous with 30% ash and more	12'1"	150.0	9
6	Dorsten, West Germany	1955	Caking subbitum. with high chlorine content	8'9"	55.0	6
7	Morwell, Australia	1955	Lignite	8'9"	22.0	6
8	Daud Khel, Pakistan	1957	High volatile coal with high sulfur content	8'9"	5.0	2
9	Sasolburg, South Africa	1958	Subbituminous with 30% ash and more	12'1"	19.0	1
10	Westfield, Great Britain	1960	Weakly caking subbituminous	8'9"	28.0	3
11	Jealgora, India	1961	Different grades	N/A	0.9	1
12	Westfield, Great Britain	1962	Weakly caking subbituminous	8'9"	9.0	1
13	Coleshill, Great Britain	1963	Caking subbituminous with high chlorine content	8'9"	46.0	5
14	Naju, Korea	1963	Graphitic anthracite	10'5"	75.0	3
15	Sasolburg, South Africa	1966	Subbituminous with 30% ash and more	12'1"	75.0	3
16	Luenen, GFR	1970	Subbituminous	11'4"	1400 MM Btu/hr	5
17	Sasolburg, South Africa	1973	Subbituminous with 30% ash and more	12'4"	190.0	3
18	Sasolburg, South Africa	1978	Subbituminous with 30% ash and more	13'1"	1500	36

which currently produces 5.4 x 10^6 Nm^3/d (200 x 10^6 scf/d) of synthesis gas in 13 Lurgi gasifiers and is being expanded to produce 40.2 x 10^6 Nm^3/d (1500 x 10^6 scf/d) in 36 gasifiers. A complete listing of Lurgi commercial installations using the West Germany technology, their locations, start-up dates and pertinent features are presented in Table 2-1.

In addition to the Lurgi process, Lurgi Mineralöltechnik GmbH has developed and/or has license on several processes for use in conjunction with the Lurgi gasification process in a commercial SNG facility. These include the gas cooling and tar/oil/gas liquor separation processes, the Rectisol acid gas treatment process and the Phenosolvan phenol recovery process. Lurgi has also developed a catalytic shift conversion process which has been extensively used in commercial operations. In addition, Lurgi has successfully pilot tested a hot gas recycle methanation system at Westfield, Scotland; Schwechat, Austria; and Sasolburg, South Africa. Finally, the Lurgi Corporation in cooperation with Chemie Linz AG of Linz, Austria has developed a process to produce anhydrous ammonia from dephenolized gas liquor. All of the above developed technologies are considered commercial by Lurgi and most are featured in the designs for proposed commercial Lurgi SNG facilities in the U.S.

Although there are currently no integrated commercial-scale facilities producing SNG in the U.S. (as well as abroad), there are several proposals for the construction of such facilities in the U.S., based on the dry ash Lurgi process(2,3). The gasification of the American coals by the Lurgi process has been evaluated in Lurgi gasifiers at the Westfield, Scotland,facility and at the SASOL plant in South Africa(4). Brief descriptions of the proposed domestic commercial SNG facilities and the results of testing of U.S. coals abroad follow.

Proposed Commercial Lurgi SNG Facilities for the U.S. The proposed commercial Lurgi SNG facilities for the U.S. which are furthest along in planning are: (a) the Mercer County, North Dakota Project sponsored by the American Natural Resources Co., the Peoples Gas Company, and the Natural Gas Pipeline Company of America; (b) the WESCO Project sponsored by Texas Eastern Transmission and Pacific Lighting Corporation to be located in northern New Mexico; (c) the Burnham, New Mexico Project, sponsored by the El Paso Natural Gas Co.; (d) Eastern Wyoming Project sponsored by Panhandle Eastern Pipeline Company; and (e) the Dunn Center Project for Dunn County, North Dakota, sponsored by the

Natural Gas Pipeline Co. of America. The status of these projects are listed in Table 2-2.

Although environmental impact statements or assessments have been completed for each of the proposed projects, legal, regulatory and funding matters are stalling initiation of construction. The Mercer County Project is the furthest along and is currently scheduled for initial construction in 1980; all required permits have been obtained, and a program for plant financing is being developed. The Federal Energy Regulatory Commission (FERC) is currently withholding approval of the Burnham facility pending resolution of matters pertaining to the acquisition of satisfactory commitments for coal and water. The WESCO project is also pending FERC certification and plant site leasing; WESCO is currently evaluating the desirability of continuing the project. A water permit application was denied in June 1976 for the Dunn Center facility, and a new water permit application is currently being developed.

In addition to the above projects, there are a number of other proposed Lurgi commercial-scale gasification projects which are in very early planning stages. These proposed projects include the Watkins, Colorado Project, sponsored by Cameron Engineers, Inc.; the Douglas, Wyoming facility, sponsored by the Panhandle Eastern Pipeline Co. and the Peabody Coal Co.*; and the Cities Service Gas and Northern Natural Gas Companies' facility planned for northern Wyoming(5,6).

Testing of American Coals in Lurgi Gasifiers Abroad. Testing has been conducted at the Lurgi facilities at Westfield, Scotland, and at Sasolburg, South Africa to assess the suitability of the Lurgi process for gasification of American coals. From 1972 to 1974, the American Gas Association and the Office of Coal Research sponsored a program to test American coals in the Lurgi facility at Westfield, Scotland. The coals tested were: Rosebud (coarse and fine grades); Illinois #5 (coarse graded and simulated run-of-mine); Illinois #6 (coarse graded and simulated run-of-mine); and Pittsburgh #8 (coarse graded and simulated run-of-mine)(7). The test results indicated that all four coals could be successfully gasified on a commercial scale in a Lurgi gasifier. Sampling and analytical activities on the feed coals, tars, oils, gas liquor,

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*This project has reached the stage of draft EIS publication, but has now been postponed indefinitely.

TABLE 2-2. STATUS OF COMMERCIAL LURGI SNG PROJECTS (AS OF SEPTEMBER, 1978)(5,6)

Sponsor	Project Acronynm	Site	Coal Feed, tonne/d (ton/d)	Peak Output, 10^6 Nm^3/d (10^6 scf/d)	Status/Miscellaneous Data
American Natural Resources Co., Tenneco, Peoples Natural Gas Co., Columbia Transmission Corp. and Transcontinental Gas Pipeline Corp.	ANG	Beulah-Hazen Area, Mercer County, N.D.	11,207 (12,328)	3.69 (137)	The plant will be built in two phases. The first phase is scheduled to be operational by the end of 1982 and will be half the size of a full commercial plant. Plant costs are estimated at $890 million (1978 dollars) with another $88 million for transmission facilities. Output from the plant is projected to cost $5.60 per Mcf not including transmission and distribution costs.
Texas Eastern Transmission Corp. and Pacific Lighting Corp.	WESCO	Four Corners Area, N.M.	22,564 (24,820)	7.38 (275)	The plan calls for construction of four plants on the Navajo Indian Reservation near Farmington, N.M. by the year 2005. Negotiations for site lease have not yet been completed. Utah International Corp. will supply the coal and water for the plant(s). Estimated project cost for the first plant is $1.4 billion (1978 dollars).
El Paso Natural Gas Co.	El Paso	Four Corners Area, N.M.	12,886 (14,175)	3.87 (155)	Plans are to construct and operate a half or quarter size plant on the Navajo Indian Reservation. A joint partnership with Rhurgas A.G. of West Germany is under consideration. A new application is expected to be filed in early 1979.
Panhandle Eastern Pipe Line Co. (mining partner: Peabody Coal Co.)	Wyoming	Eastern Wyoming	25, 182 (27,700)	7.38 (275)	Plans remain in a holding stage. Investment costs are estimated at $1.3 billion (early 1976 dollars). No filing has yet been made to the FERC.
Natural Gas Pipeline Co. of America	Dunn Co.	Dunn County, N.D.	27,273 (30,000)	7.25 (270)	Phase I engineering design has been completed. No filing has been made with the FERC. Further action on the project is currently under review.

flash gas, flare gas and product gas were also performed as part of the program. At the Westfield facility the American coals have also been successfully treated using the slagging Lurgi gasification process. (The slagging Lurgi process is not addressed in this document.)

At the SASOL plant in South Africa, Texas lignite has been gasified in a program sponsored by the Exxon Corporation(8). Technical evaluations of the test runs are to be completed in early 1979. If favorable, Exxon may construct a 38,000-tonne/d (41,900-ton/d) plant at Troup, Texas in the early 1980's. In 1974, 10,900 tonne (12,000 ton) of North Dakota lignite were gasified in a Lurgi gasifier at the Sasolburg facility under the sponsorship of the Michigan-Wisconsin Gas Pipeline Company. The results of the tests indicated that the lignite could be satisfactorily processed in the Lurgi gasifier. A secondary objective of the program was the determination of trace element distributions in gasifier ash, tars, oils, and gas liquors. Using spark source mass spectrometry as the analytical method, trace element compositions were determined on all effluents sampled(9).

2.1.2 Industrial Applicability of Lurgi Systems

As discussed in Section 2.3, the Lurgi gasification process can be used for production of low or medium Btu gas which can be used as an industrial fuel, as chemical feedstocks and/or for SNG production. This document focuses solely on Lurgi systems for SNG production. In principle, SNG should be substitutable for natural gas in essentially all applications. Depending on whether the high costs of SNG are allowed by the FERC* to be recovered by "incremental" pricing or "rolled in" pricing and on curtailment procedures based on end use criteria, SNG may not be economical or allowed for certain applications. At the present time the issue of pricing and curtailment is being handled by the FERC on a case-by-case basis and no definite precedent has been established. It appears likely, however, that some restrictions, either directly or indirectly via pricing mechanisms, will be placed on end uses deemed undesirable, inefficient, or unnecessary. An example of such a use of SNG would be ammonia production, where gasifying coal at the ammonia plant site for hydrogen production would represent a more efficient resource use than reforming coal-derived SNG to produce the same amount of hydrogen.

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*Although the production of SNG is not subject to regulation by the FERC, the transportation and/or sale of such gas in interstate commerce is under the jurisdiction of this agency(10). All proposed Lurgi gasification facilities in the U.S. would be subject to regulation since the product SNG would be sold interstate. By virtue of its rate structure setting power over the gas pipeline transmission industry, the FERC in effect has control over the economics of manufacturing gas for interstate commerce.

2.1.3 Input Materials, Products and Byproducts

Input materials used in various processes in Lurgi systems for SNG production include: coal, oxygen, methanol, propylene, isopropyl ether, sulfuric acid, caustic soda, lime, limestone, calcium sulfate, magnesium sulfate, catalysts (cobalt molybdate and nickel-based catalysts, and sulfur plant catalysts), methanation guard material (e.g., zinc oxide, iron oxide), sodium sulfite, phosphates, alum, polyelectrolytes, chlorine, corrosion inhibitors and phosphoric acid. Table 2-3 summarizes the uses of these chemicals in Lurgi systems, the approximate quantity used, and their commercial availability and hazard rating. As indicated in the table, all of the input materials are readily available. The inorganic input materials, which include oxygen, sulfuric acid, caustic soda, etc., are widely used in a number of industrial applications, and supplies of these materials are well established.

Supplies of organic chemicals are also generally well established. U.S. Tarrif Commission product data indicate the following production quantities for 1973 for the subject organics(11); methanol, 3,203,692 tonne (3,532,185 ton); propylene, 4,482,427 tonne (4,942,036 ton); and isopropyl ether (quantity sold), 4,439 tonne (4,895 ton). Based on these data and those in Table 2-3, a 7×10^6 Nm^3/d (250×10^6 scf/d) Lurgi SNG facility would consume less than 0.14% of the U.S. production of methanol and less than 0.01% of the U.S. production of propylene. The quantity of isopropyl ether required in a commercial facility would amount to 23.7% of the reported quantity sold in the U.S. in 1973. Since the actual U.S. production capacity of isopropyl ether is not known, it is difficult to predict the impact of usage of the chemical for SNG production on the U.S. market and it is possible that certain increases in the U.S. production capacity would be required to accommodate the increased demand.

It is not known exactly how much nickel, cobalt and molybdenum are in use in catalysts in the U.S. A recent estimate of catalyst metals content has been made, which indicates 1,360 tonne (1,500 ton) of molybdenum and 453 tonne (500

TABLE 2-3. INPUT MATERIALS ASSOCIATED WITH COMMERCIAL LURGI SNG FACILITIES

Input Material	Use in Lurgi System	Approximate Quantity*	Comment†	Reference
Coal	Raw fuel feed	22,240 - 29,450 tonne/d (24,521 - 32,470 ton/d)	Commercially available, usually in close proximity to gasification facility; non-hazardous	13,14,15, 2,3
Oxygen	Input raw material to gasifier	2,500 - 5,442 tonne/d (2,700 - 6,000 ton/d)	Commercially available; non-toxic, non-hazardous under conditions of proper use	14,15,3
Methanol	Rectisol solvent	5,680,150 l/yr (1,500,700 gal/yr)	Commercially available; MEG rating-non-hazardous	3
Propylene	Rectisol solvent	138,153 l/yr (36,500 gal/yr)	Commercially available; MEG rating-non-hazardous	3
Isopropyl ether	Phenosolvan solvent	1,052 tonne/yr (1,160 ton/yr)	Commercially available; hazardous properties - toxic by ingestion and inhalation, flammable	3
Sulfuric acid (93%)	Water treating and cooling tower	6,440 tonne/yr (7,100 ton/yr)	Commercially plentiful; hazardous properties - highly toxic, a strong irritant, corrosive	3
Caustic soda (50%)	Water treating and Rectisol unit	12,970 tonne/yr (14,300 ton/yr)	Commercially plentiful; hazardous properties - highly toxic; a strong irritant	3
Lime	Water treating and Phenosolvan	10,884 tonne/yr (12,000 ton/yr)	Commercially available; hazardous properties - a strong irritant, reactive with organic materials	3
Limestone	Stack and tail gas treating	40,996 tonne/yr (45,200 ton/yr)	Commercially available; considered non-hazardous	3
Dessicants (e.g. $CaSO_4$)	Oxygen plant	1.36 tonne/yr (1.5 ton/yr)	Commercially available; considered non-hazardous	3

TABLE 2-3. CONTINUED

Input Material	Use in Lurgi System	Approximate Quantity*	Comment[+]	Reference
Catalyst (e.g., alumina or bauxite)	Sulfur plant	60.5 tonne/yr (66.5 ton/yr)	Commercially available	3
Catalyst (e.g., cobalt molybdate)	Shift conversion unit	485,630 l/yr (17,160 cu ft/yr)	Commercially available; MEG rating-very hazardous	3
Catalyst (e.g., nickel-based)	Methanation unit	Not available	Commercially available; MEG rating-most hazardous	3
Sulfur guards (e.g., zinc oxide, iron oxide)	Methanation unit	Not available	Commercially available; MEG rating-non-hazardous	3
Other water and wastewater treatment chemicals (e.g., sodium sulfite, phosphate, alum, polyelectrolytes, chlorine, corrosion inhibitors and phosphoric acid)	Water treating and cooling tower	Not available	Commercially available; non-hazardous	3

*Quantity associated with 7 x 10^6 Nm^3/d (250 x 10^6 scfd) commercial-scale facility.

[+] EPA MEG hazard ratings (see Section 5.1.1) are used as the basis of the hazard classification assigned, where applicable. Where unavailable, hazardous properties are described, based on Reference 16.

ton) of nickel and cobalt were in catalysts in commercial use (mainly in refinery applications) in 1975(12). A 1977 estimate indicates a 60 percent increase in Mo, Ni, and Co-containing catalyst usage by 1980(12). The increased demand for specialty catalysts may result in increased production and/or recycyling of catalyst metals for domestic use. The U.S. currently has abundant supplies of molybdenum. Although U.S. nickel and cobalt supplies are less abundant, domestic and foreign supplies are currently available, and it is anticipated that domestic production and/or imports will continue to provide U.S. requirements through the year 2000(17).

U.S. production of molybdenum and nickel in 1974 was 34,600 tonne (38,200 ton) and 13,600 tonne (15,000 ton), respectively. Although the U.S. has not actively produced cobalt since 1971, the quantity of cobalt used in 1974 (which came mainly from imports and from U.S. reserves) was approximately 15,600 tonne (17,200 ton)(17). Based on the data in Table 2-3, a 7 x 10^6 Nm^3/d (250 x 10^6 scf/d) Lurgi SNG facility would consume only about 0.12% of the cobalt used annually, which does not represent a significant fraction of annual imports/reserves.

The U.S. currently has abundant supplies of bauxite. Known reserves of commercial bauxite in the U.S. are estimated to be approximately 40.8 million tonne (45 million ton). About 6.25 million tonne (6.9 million ton) of aluminum (25 million tonne or 29.6 million ton of bauxite) were produced in the U.S. in 1968; this production rate has increased several percent annually for the past 10 years, and is expected to continue to increase at about the same rate in the future. Based on the data in Table 2-3, a 7 x 10^6 Nm^3/d (250 x 10^6 scf/d) Lurgi SNG facility would consume less than 0.01% of the annual U.S. production of aluminum (and bauxite) which represents an insignificant fraction of the annual production(17).

As indicated in Table 2-3, only the cobalt molybdate and nickel-based catalysts are rated "very hazardous" materials. The hazard ratings in the table are based on EPA's Multimedia Environmental Goals (MEG) classification system (see Section 5.1.1); where no MEG rating was available for a specific chemical, general toxicological and other hazardous properties are presented. Because of their toxic properties, flammability, reactivity and/or corrosivity, isopropyl ether, sulfuric acid, caustic soda and lime are considered hazardous.

Coal, oxygen, methanol, propylene, limestone, dessicants, the sulfur guards and other water and wastewater treatment chemicals are considered non-hazardous under conditions of proper handling and use.

Product and byproducts associated with Lurgi SNG plants include product SNG, crude phenols, naphtha, tars, oils, sulfur and ammonia (see Table 2-4 for approximate quantities). Although markets exist for all of these materials, the largest markets are associated with product SNG, ammonia (for use in fertilizers, refrigerants, and dye synthesis), sulfur (for use in sulfuric acid manufacture, pulp and paper manufacture, etc.) and crude phenols (for organic synthesis, pharmaceutical manufacture, nylon, etc.). A limited market exists for naphtha, tars, oils and phenols which can be sold as fuel or for chemical feedstocks.

As indicated in Table 2-4, the product and many of the by-products associated with Lurgi SNG systems are toxic to some degree, are irritants to the skin or eyes, are carcinogenic, and/or present fire or explosion hazards. The hazardous properties of sulfur, naphtha, tars, oils, crude phenols, ammonia and SNG are further discussed in Section 3.4 and 4.5. Some of these materials (i.e., ammonia, SNG, phenols) have strict transportation standards, as regulated by the Interstate Commerce Commission, Coast Guard, and/or the International Air Transport Association(16,18).

2.1.4 Energy Efficiencies

The thermal efficiency of Lurgi SNG facilities will depend upon the properties of the feed coal, the overall plant design including utility and pollution control processes used, and the extent to which efficient steam/power generation are integrated in the plant. For the proposed commercial Lurgi SNG facilities in the U.S. about 70 to 80% of the input coal energy is found in product SNG, tars, oils, naphthas and phenols, based upon higher heating values(19). If these plants were entirely self-supporting in terms of energy, the overall thermal efficiency would be about 65% for lignites(20) and 67% for bituminous and subbituminous coals(20,21). Actual operating data from the SASOL Lurgi facility in South Africa indicate an overall thermal efficiency of about 76% for the combined gasification, gas cooling and tar/oil/gas liquor separation(19). Thus, about 9 to 11% thermal efficiency loss may be expected for gas purification and upgrading and pollution control. Recent estimates of energy requirement

TABLE 2-4. PRODUCT AND BYPRODUCTS ASSOCIATED WITH LURGI GASIFICATION(2,3,13,14,15)

Product and Byproduct	Approximate Quantity*	Comments†
SNG	7×10^6 Nm^3/d (250×10^6 scf/d)	Principal product; flammable, a fire and explosion risk if improperly handled.
Crude phenols	30,720-49,360 tonne/yr (33,870-54,431 ton/yr)	Marketed liquid byproduct; MEG rating-hazardous.‡
Tars	223,738-305,875 tonne/yr (246,680-337,239 ton/yr)	Marketed semi-liquid byproduct; hazardous properties - highly toxic, carcinogenic.
Oils	54,743-175,689 tonne/yr (60,347-193,074 ton/yr)	Marketed liquid byproduct; hazardous properties - moderately toxic; skin and eye irritant.
Sulfur	52,968-60,977 tonne/yr (58,400-67,230 ton/yr)	Marketed solid or liquid (phase determined by customer demand); non-hazardous.
Ammonia	33,941-71,177 tonne/yr (37,422-78,475 ton/yr)	Marketed, usually as anhydrous ammonia; MEG rating - non-hazardous.
Naphtha	25,027-68,966 ton/yr (27,594-76,037 tonne/yr)	Marketed liquid; hazardous properties - flammable; toxic by ingestion, inhalation and skin absorption.

*Quantity associated with 7×10^6 Nm^3/d (250×10^6 scf/d) commercial-scale facility.

†EPA MEG hazard ratings are used as the basis of the hazard classification assigned, where applicable. Where unavailable, hazardous properties are described, based on Reference 16.

‡MEG rating based on purified phenol; crude phenols are expected to be hazardous.

for pollution control in Lurgi SNG facilities indicate that from 3.6 to 5.6% of the plant input is needed for air pollution control(22). Although some uncertainties are involved in the above calculations of thermal efficiencies, the data indicate the approximate energy balance which may be expected for integrated commercial Lurgi SNG plants.

2.1.5 Capital and Operating Costs

Individual Lurgi SNG facilities which have been proposed have a capacity of about 7 x 10^6 Nm^3/d or 250 x 10^6 scf/d of product gas, although during initial operation output may be considerably smaller than this amount. Numerous estimates have been made of the economics of SNG production, and a few selected estimates are summarized in Table 2-5 for a facility of the above size. As shown by the data, estimated investment costs for SNG facilities have increased dramatically in the last few years, reflecting in part the impact of inflation on the economics of large scale capital-intensive projects. Differences between the estimates in the table can also be partially attributed to different assumptions about the financing method and discount rate and the inclusion or non-inclusion of mine investment costs. Despite the differences in the estimates, it appears that a 7 x 10^6 Nm^3/d (250 x 10^6 scf/d) facility will require a capital investment of as much as $2 billion (1978 dollars) if electric power generation and mine investment are included. Annual operating costs of around $300 million may be anticipated for such a facility. These costs translate into a required gas selling price of around $20/$10^6$ kcal ($5/$10^6$ Btu) at the plant, a price well above the current price of even the most expensive natural gas at the wellhead.

Table 2-6 presents a breakdown of Lurgi SNG investment costs by category of processes or operations. Coal preparation, gasification, quench and shift collectively account for about one-fourth to one-third of the total plant investment. Utilities and general facilities account for about an additional one-third. Capital investment for pollution control is estimated at 2 to 7% of the total.

Operating costs associated with pollution control are not an insignificant fraction of total operating costs. One estimate for air pollution control operating costs at a 7 x 10^6 Nm^3/d (250 x 10^6 scf/d) Lurgi SNG facility is $20 million per year or around 7% of the $300 million annual operation costs(22).

TABLE 2-5. SELECTED ESTIMATES OF CAPITAL COST AND GAS SELLING PRICE FOR LURGI-BASED SNG FACILITIES (62×10^9 kcal/d or 250×10^9 Btu/d basis)

Year of Estimate	Reference	Capital Investment $\$10^6$	Gas Selling Price $\$/10^6$ kcal ($\$/10^6$ Btu)	Annual Operating Costs $\$10^6$
1972	19	330	--*	--
1973	23	605	4.92 (1.23)	--
1974	24	450†	7.28 (1.84)	--
1975	25	738†	16.80 (4.20)§	140 - 172
1976	26	1060	12.88 (3.22)#	--
1977	27	814‡	10.68 (2.67)	133
1977	28	970‡	14.92 (3.73)	--
1978	5	1400	--	--
1978	29	1910	20.60 (5.15)	287
1978	6	1624‡	22.64 (5.66)**	--

*Not available

†Exclusive of mine investment

‡Assumes no on-site power generation

§15% DCF assumed

#Utility financing basis

**Cost for 1983 in 1978 dollars; cost will decrease to $\$16.50/10^6$ kcal or $\$4.13/10^6$ Btu over the 25 year plant life

TABLE 2-6. BREAKDOWN OF CAPITAL INVESTMENT COST FOR LURGI SNG FACILITIES (IN PERCENT OF TOTAL CAPITAL COST)

Operations/Processes	Reference 25	Reference 26
Coal preparation, gasification, heat recovery, quench, tar oil separation, and shift	36	22
Acid gas removal	7.4	11
Methanation, compression and drying	8.1	5.5
Air pollution control and wastewater treatment	3.3	7.2
Steam, water, utilities and general plant facilities	26	29
Interest, depreciation and working capital	20	22
Total	100	100

2.1.6 Commercial Prospects

Factors Affecting the Development of an SNG Industry. As discussed in Section 2.1.1, none of the proposed Lurgi-based SNG projects has reached the "start of construction" stage. Sponsors of these projects had hoped for federal loan guarantees to allow the projects to proceed but in the fall of 1977 the Federal Loan Guarantee Program bill was vetoed by the President. Since that time at least two of the projects have been restructured to obtain additional sponsors. The size of the first facilities to be constructed have also been reduced to minimize the initial capital investment(5,6). Major uncertainties for the developers are the FERC's position on allowing for the recovery of costs associated with the first plants and the DOE role in directly or indirectly assisting the financing of SNG plants.

In addition to the economic uncertainties which cloud the development schedule for SNG facilities, a number of other factors may affect the rate at which the SNG industry develops. Some of these factors are institutional, such as the ability to obtain water permits (e.g., in the case of the Dunn County Project) and disputes over lease arrangements (e.g., in the case of the WESCO Project which involves Navajo lands). Other factors involve the technical logistics of SNG facilities such as the availability of skilled construction labor and steel fabricating shop capacity. For example, about 60,000 tonne (66,150 ton) of fabricated steel are estimated to be required for just one 7×10^6 Nm^3/d (250×10^6 scf/d) SNG facility, a quantity which represents a sizeable fraction of existing annual U.S. shop capacity(30). Finally, there is the problem of local and national opposition to large scale industrial or energy projects which has in recent years led to many delays and/or project cancellations. Even when such opposition has been overcome by legal actions or appeasement measures, ultimate project costs are generally increased by significant amounts. Although the above factors are difficult to quantify in terms of their impact on the development schedule and cost of projects, recent history suggests that significant time delays and greatly increased costs are likely to be associated with the development of a viable SNG industry.

The Siting of Lurgi SNG Facilities. Although a variety of factors influence the choice of a site for a commercial gasification plant, perhaps the most important from an economic standpoint is the availability of a large reliable and inexpensive source of coal. This is the major reason why all proposed commercial SNG facilities to date are to be located in the west. Strip-mined coal in the west is commonly less expensive than strip or deep-mined coal in the midwest or east and the large quantities needed daily and over the life of the plants are more readily obtainable from western strip mines. SNG plants located in the midwest and east may have certain advantages over western plants such as lower gas transmission costs to market. It is expected that most plants east of the Mississippi River will likely be of smaller size than those in the west since the quantities of coal needed for a large gasification plant (20,000-25,000 tonne/d or 22,000-27,000 ton/d) are difficult to obtain from underground mines and most eastern strip mines.

Two major site-related factors have been identified which appear to be most important in determining plant design from an environmental standpoint. These are (1) coal type to be used at the facility and (2) regional water availability and climate. Coal type influences the design of sulfur recovery and air pollution control units and wastewater treatment units since the amounts of sulfur and moisture in coal (largely a function of coal type) determine the quantity of H_2S in raw product gas and the quantity of gas liquor generated, respectively. Generally, western subbituminous and lignitic coals have low sulfur and moderate to high moisture contents, while midwestern and eastern coals have high sulfur and low moisture contents.

Regional climate is of major importance since it largely determines the availability and cost of raw water and the options for ultimate disposal of plant wastewater. In the western U.S., water is generally less available and more expensive than in the east. Consequently, wastewater treatment for reuse and recycle will be more economical for western plants while discharge of treated wastewater (if allowed) would probably be more economic in the east. In addition, western facilities will have the option of ultimate disposal of all or part of their wastewater by solar evaporation. Use of evaporation ponds is not generally feasible east of the Mississippi River.

2.2 DESCRIPTION OF PROCESSES

This section presents a discussion of processes and unit operations which are associated with Lurgi systems for SNG production. The information contained in this section has been derived from the designs for proposed commercial Lurgi facilities(2,3,13,14,15,20,21), the designs and operating features of existing Lurgi gasification facilities abroad(4,7,34,44), and from published literature relating to engineering and environmental aspects of Lurgi systems(22,23,24,30,41). The discussion covers alternate processes/unit operations which may be employed in Lurgi systems in addition to standard Lurgi-licensed technologies. The engineering descriptions of production and auxiliary processes are in sufficient detail to enable comparison of waste stream control alternatives. The auxiliary processes used for wastewater control and solids disposal are reviewed very briefly.

2.2.1 Generalized Process Flow Diagrams

Figure 2-1 is a simplified flow diagram of operations and processes which constitute Lurgi systems for SNG production. SNG production includes the following four operations: (1) coal preparation, (2) coal gasification, (3) gas purification, and (4) gas upgrading. Major auxiliary processes associated with a commercial Lurgi SNG facility include processes for air pollution control, water pollution control, solid waste management, steam and power generation, oxygen production, and raw water treatment. Figure 2-2 is a more detailed block flow diagram of operations involved in gas production and shows the major process and waste streams associated with these operations. This flow diagram with numbered streams will serve as one of three master flow diagrams which will be referred to throughout the report. Two other flow diagrams (Figures 2-3 and 2-4) show pollution control and non-pollution control auxiliary processes, respectively. Table 2-7 provides an identification index to the stream numbering system used on various flow diagrams. Sections 2.2.2, 2.2.3 and 2.2.4 which follow provide brief engineering descriptions of the operations in Figure 2-2 with emphasis on the origin and nature of waste streams. Section 2.2.5 discusses auxiliary processes.

2.2.2 Coal Pretreatment

The Lurgi gasifier can handle, without coal pretreatment, many types of coals having varied heat valves, ash and moisture contents, and swelling and caking tendencies. The rotating distributor in the gasifier counteracts the caking tendency of caking coals. The distributor has proven successful in preventing caking and plugging problems during gasification tests with Illinois and Pennsylvania coals with high swelling and caking indices (7). High ash and moisture contents in coals can decrease gasifier temperatures and thermal

TABLE 2-7. INDEX TO STREAM NUMBERING SYSTEM USED IN VARIOUS FLOW DIAGRAMS

Stream No.	Stream Name	Stream No.	Stream Name
1	Raw coal	51	Hydrocarbon rich offgas
2	Fugitive coal dust	52	Recycle H_2S
3	Coal fines	53	Spent sorbents/reagents
4	Coal refuse	54	Sulfate/sulfite sludge
5	Sized coal	55	Spent filter media
6	Coal lockhopper vent gas	56	Enriched H_2S Claus feed
7	Coal lockhopper supply gas	57	Sulfur recovery
8	Ash lockhopper vent gas	58	Methanation guard
9	Steam	59	Sulfur
10	Oxygen	60	Dehydrating agent
11	Raw product gas	61	Atmospheric discharge
12	Ash	62	Particulate free boiler flue gas
13	Raw gas liquor	63	Boiler ash
14	By-pass gas (cooled raw gas)	64	Utility boiler flue gas
15	Cooled raw gas	65	Air
16	Shifted gas	66	Nitrogen
17	Combined shifted and cooled raw gas	67	Shift catalyst
18	Still bottoms	68	Desulfurized fuel gas
19	Make-up methanol	69	Depressurization gas
20	Naphtha	70	Tar
21	Expansion gas	71	Oil
22	Lean H_2S gas	72	Oil and tar free gas liquor
23	Rich H_2S gas	73	Methanation catlyst
24	CO_2/H_2S free product gas	74	Solvent makeup
25	Spent shift catalyst	75	Dephenolized gas liquor
26	Methanator feed gas	76	Filter backwash
27	Catalyst regeneration/off-gas	77	Phenol
28	Methanated product gas	78	Ash quench offgas
29	Methanation condensate	79	Ash quench water
30	Spent methanation catalyst	80	Ash slurry
31	Drying and compression condensate	81	Stripper offgas
32	Dry SNG	82	Clean gas liquor
33	Boiler feed water	83	Ammonia
34	Raw water	84	Clarified effluent
35	Coagulant (aluminum and ferric salts)	85	Dewatered ash solids
36	Polymers	86	Boiler blowdown
37	Chlorine compounds	87	Evaporation/drift
38	Alkali (lime, caustic soda, etc.)	88	Sulfuric acid
39	Coagulation/settling sludges	89	Antifoam agent
40	Clarified water	90	Biocide
41	Backwash water	91	Corrosion inhibitors
42	Filtered water	92	Biological clarified effluent
43	Acid regenerant	93	Biological sludge
44	Base regenerant	94	Oil free water
45	Salt	95	Cooling tower blowdown
46	Softened water (boiler feedwater)	96	Tarry/oily sludges
47	Demineralized water (boiler feedwater)	97	Low oil content water
48	Spent methanation guard	98	Sanitary wastewater
49	Regeneration blowdown/sludges	99	Clean water
50	Atmospheric discharge	100	Plant run-off water
		101	Byproduct storage vent gases
		102	Transient waste gases

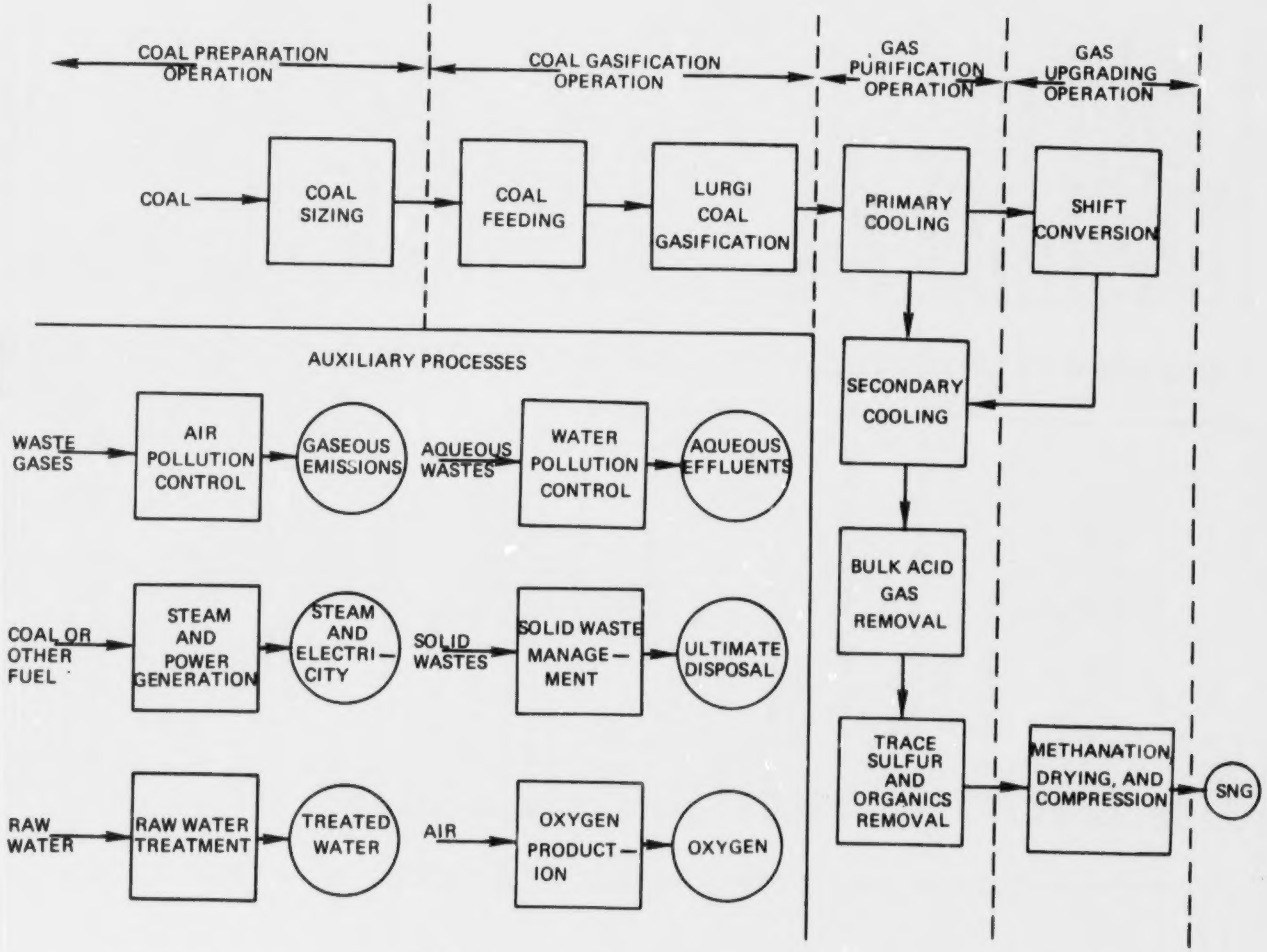
COAL PREPARATION OPERATION
COAL GASIFICATION OPERATION
GAS PURIFICATION OPERATION
GAS UPGRADING OPERATION
COAL
COAL SIZING
COAL FEEDING
LURGI COAL GASIFICATION
PRIMARY COOLING
SHIFT CONVERSION
SECONDARY COOLING
BULK ACID GAS REMOVAL
TRACE SULFUR AND ORGANICS REMOVAL
METHANATION, DRYING, AND COMPRESSION
SNG
AUXILIARY PROCESSES
WASTE GASES
AIR POLLUTION CONTROL
GASEOUS EMISSIONS
AQUEOUS WASTES
WATER POLLUTION CONTROL
AQUEOUS EFFLUENTS
COAL OR OTHER FUEL
STEAM AND POWER GENERATION
STEAM AND ELECTRI-CITY
SOLID WASTES
SOLID WASTE MANAGE-MENT
ULTIMATE DISPOSAL
RAW WATER
RAW WATER TREATMENT
TREATED WATER
AIR
OXYGEN PRODUCT-ION
OXYGEN

Figure 2-1. Generalized Process Flow Diagram for Lurgi Systems Producing SNG

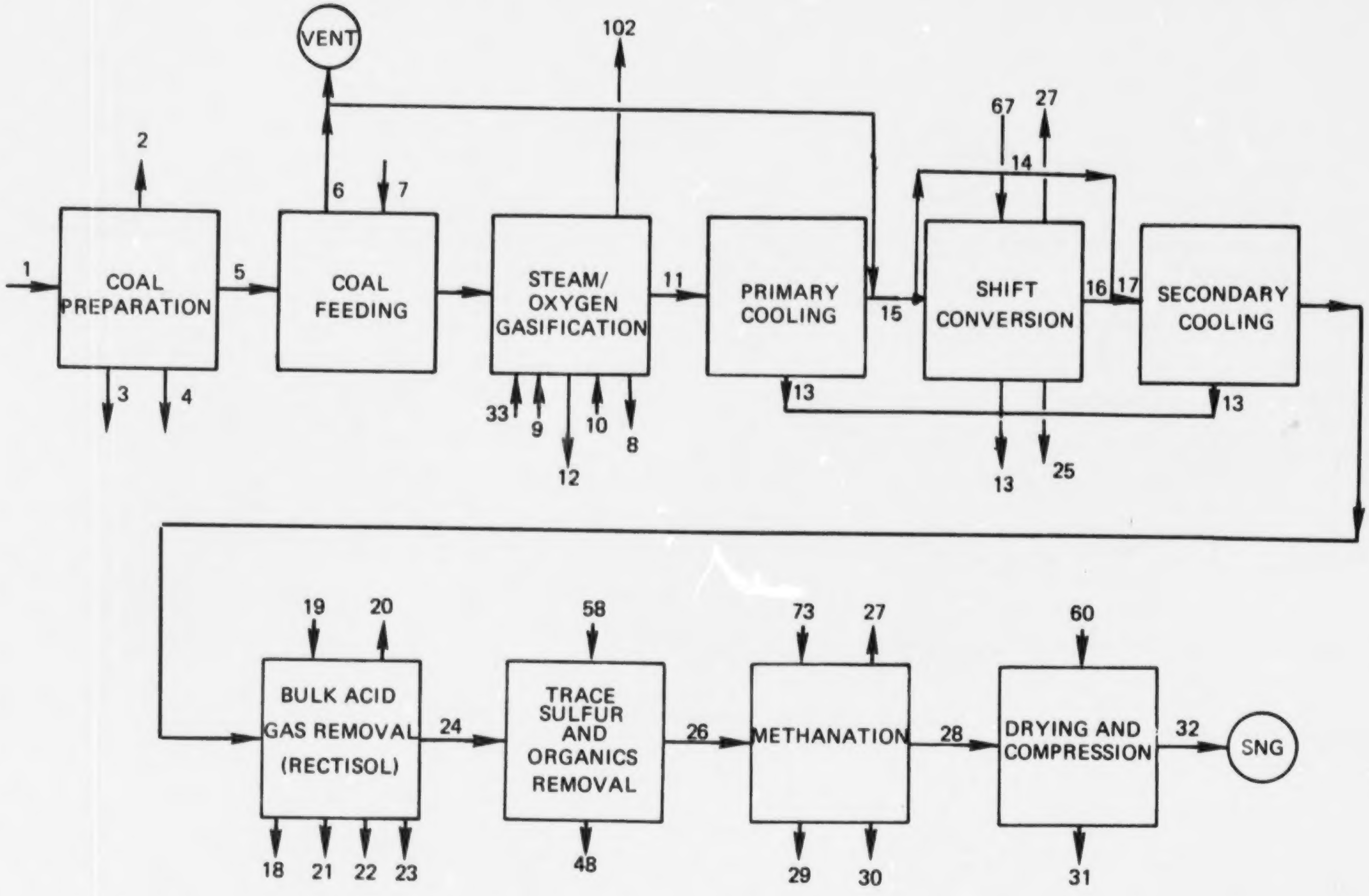
VENT
102
2
6
7
1
COAL PREPARATION
5
COAL FEEDING
STEAM/ OXYGEN GASIFICATION
11
PRIMARY COOLING
15
67
27
14
SHIFT CONVERSION
16
17
SECONDARY COOLING
3
4
33
9
10
8
12
13
13
13
25
19
20
BULK ACID GAS REMOVAL (RECTISOL)
24
58
TRACE SULFUR AND ORGANICS REMOVAL
26
73
27
METHANATION
28
60
DRYING AND COMPRESSION
32
SNG
18
21
22
23
48
29
30
31

Figure 2-2. Flow Diagram for Processes in Lurgi Systems for Producing SNG (see Table 2-7 for Index to Streams; Stream Numbering System is Consistent with Those Shown in Figures 2-3 and 2-4)

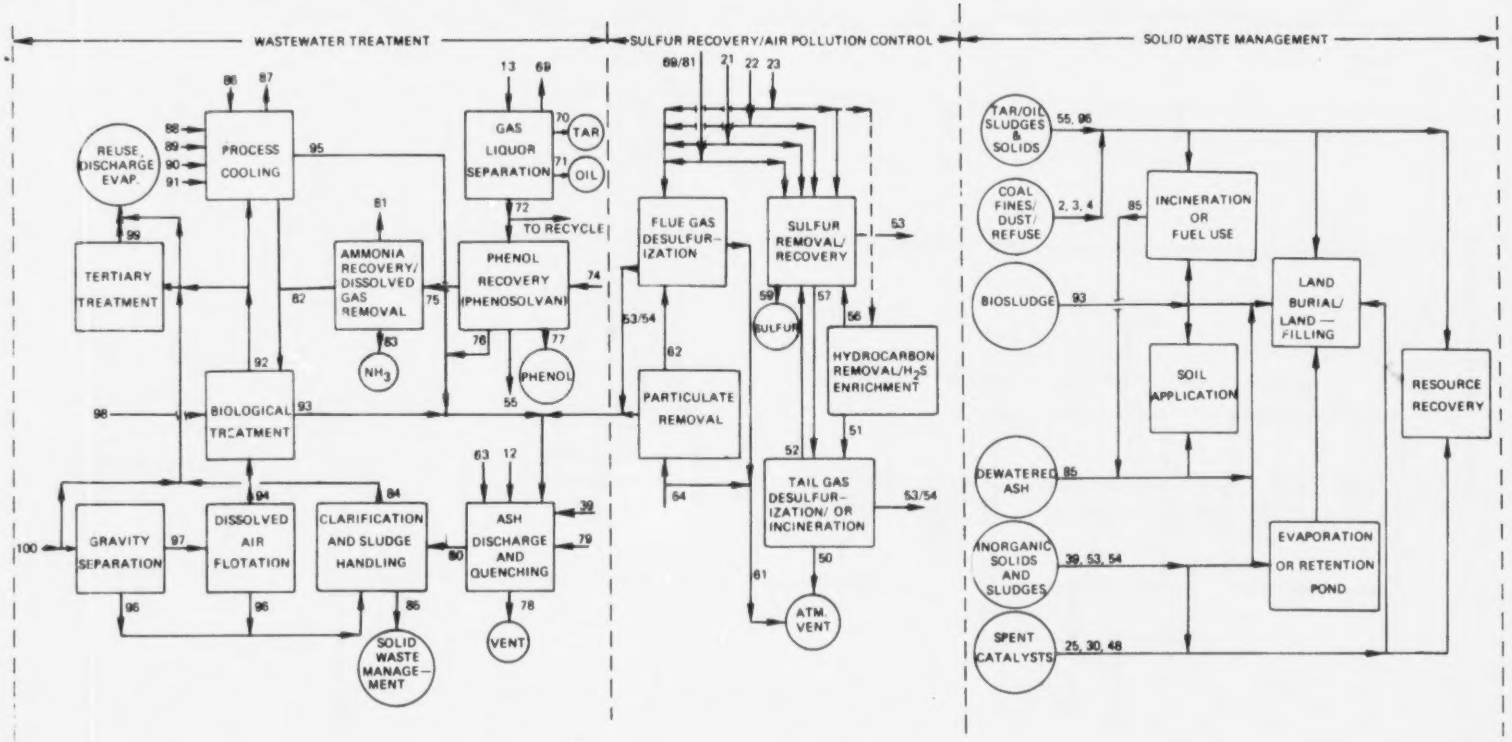
WASTEWATER TREATMENT
SULFUR RECOVERY/AIR POLLUTION CONTROL
SOLID WASTE MANAGEMENT
REUSE, DISCHARGE EVAP.
PROCESS COOLING
GAS LIQUOR SEPARATION
TAR
OIL
TO RECYCLE
AMMONIA RECOVERY/ DISSOLVED GAS REMOVAL
NH3
PHENOL RECOVERY (PHENOSOLVAN)
PHENOL
TERTIARY TREATMENT
BIOLOGICAL TREATMENT
GRAVITY SEPARATION
DISSOLVED AIR FLOTATION
CLARIFICATION AND SLUDGE HANDLING
SOLID WASTE MANAGE-MENT
ASH DISCHARGE AND QUENCHING
VENT
FLUE GAS DESULFUR-IZATION
PARTICULATE REMOVAL
SULFUR REMOVAL/ RECOVERY
SULFUR
HYDROCARBON REMOVAL/H2S ENRICHMENT
TAIL GAS DESULFUR-IZATION/ OR INCINERATION
ATM. VENT
TAR/OIL SLUDGES & SOLIDS
COAL FINES/ DUST/ REFUSE
BIOSLUDGE
DEWATERED ASH
INORGANIC SOLIDS AND SLUDGES
SPENT CATALYSTS
INCINERATION OR FUEL USE
SOIL APPLICATION
LAND BURIAL/ LAND — FILLING
EVAPORATION OR RETENTION POND
RESOURCE RECOVERY
86
87
88
89
90
91
95
99
81
82
83
75
76
13
69
70
71
72
74
77
55
92
93
98
94
84
100
97
96
96
85
80
63
12
39
79
78
69/81
21
22
23
53
53/54
62
64
59
57
56
51
52
50
61
53/54
55, 96
2, 3, 4
85
93
85
39, 53, 54
25, 30, 48

Figure 2-3. Flow Diagram for Pollution Control Auxiliary Processes Associated with Lurgi Systems (see Table 2-7 for index to streams; stream numbering system is consistent with those shown in Figure 2-2 and 2-3)

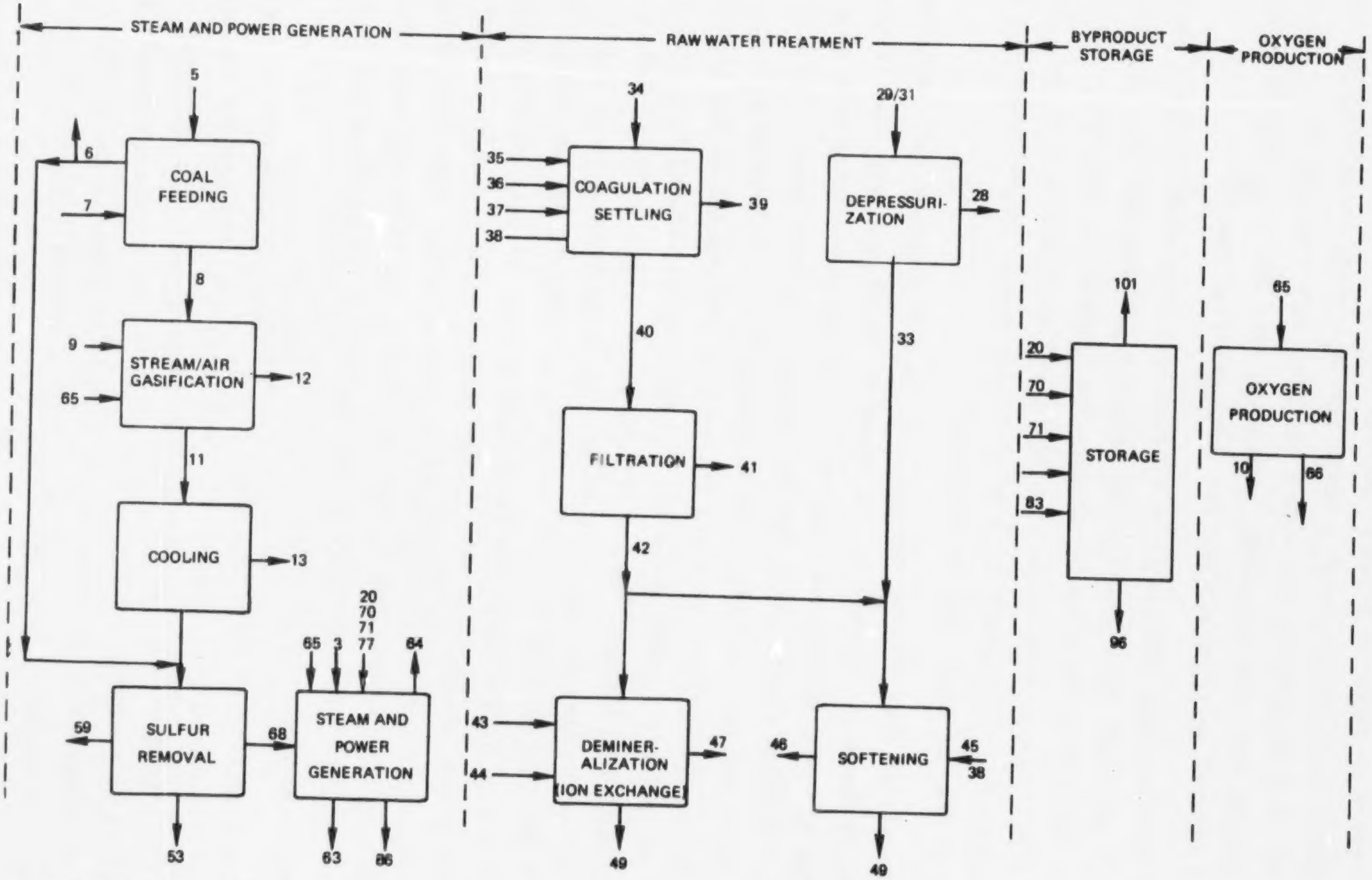
STEAM AND POWER GENERATION
RAW WATER TREATMENT
BYPRODUCT STORAGE
OXYGEN PRODUCTION
5
6
7
COAL FEEDING
8
9
65
STREAM/AIR GASIFICATION
12
11
COOLING
13
59
SULFUR REMOVAL
53
68
65
3
20
70
71
77
64
STEAM AND POWER GENERATION
63
86
34
35
36
37
38
COAGULATION SETTLING
39
40
FILTRATION
41
42
43
44
DEMINER-ALIZATION (ION EXCHANGE)
47
49
29/31
DEPRESSURI-ZATION
28
33
46
SOFTENING
45
38
49
20
70
71
83
STORAGE
101
96
65
OXYGEN PRODUCTION
10
66

Figure 2-4. Flow Diagram for Non-Pollution Control Auxiliary Processes Associated with Lurgi Systems for SNG Production (see Table 2-7 for Index to Streams; Stream Numbering System is Consistent with Those Shown in Figures 2-2 and 2-3)

efficiencies but generally do not prohibit the use of such coals. Certain coals (e.g., lignites) with moisture contents above 35 to 40% may require drying before gasification in order to prevent condensation of moisture in the gasifier (tests at SASOL, South Africa, with a North Dakota lignite containing 36% moisture resulted in a raw product gas with a gasifier exit temperature only 30°K or 50°F above the moisture dew point, indicating that 36% is approaching the upper limit of coal moisture content for Lurgi gasifier feed)(9).

Lurgi gasifier feed (Stream 5) is limited to a size which is small enough to allow for efficient heat transfer and complete gasification but large enough to minimize channeling and plugging of gas flow through the coal bed. Based on operating experience, a size range of 0.32 to 3.5 cm (0.125 to 1.38 in.) is usually required(1). To obtain coal in this size range, proper crushing and screening of "run of mine" coal is required.

A generalized flow diagram for coal preparation proposed for commercial facilities is shown in Figure 2-5. As shown in the figure, raw coal is transported from the mine to the dump hoppers at the coal preparation area adjacent to the gasification plant. From the coal hoppers the coal enters the primary crushers where the coal is reduced to a nominal size of approximately 15 to 20 cm (6 to 8 in.). From primary crushers the coal is transported to the secondary crushers and primary screens where the crushed coal is reduced to a size suitable for feeding to the gasifiers. In some cases (e.g., in the El Paso Burnham design) two coal sizes are to be produced - 44 mm to 8 mm (1.76 to 0.32 in.) and 8 mm to 2 mm (0.32 to 0.08 in.)(31). The larger size is for SNG production and the smaller size is for power and steam generation. Primary screens separate the oversize coal (>44mm or 1.75 in.) for return to the secondary crushers. The primary sized coal is transferred to a storage area. Coal from storage is fine screened before conveying to the gasifiers. The fines are usually cleaned (e.g., as in the El Paso Burnham design) and either sold or used for on-site power or steam generation.

At all transfer points, crushers and screens fugitive emissions containing coal dust are generated (Stream 2). Two methods are proposed for the control of the fugitive dust: (1) collecting the dusty gases via a pneumatic system and routing to a baghouse or venturi scrubber for particulate removal, and (2) use of water sprays at all transfer points and at crushers and screens. The major wastewater generated by the coal preparation operation is the runoff from the

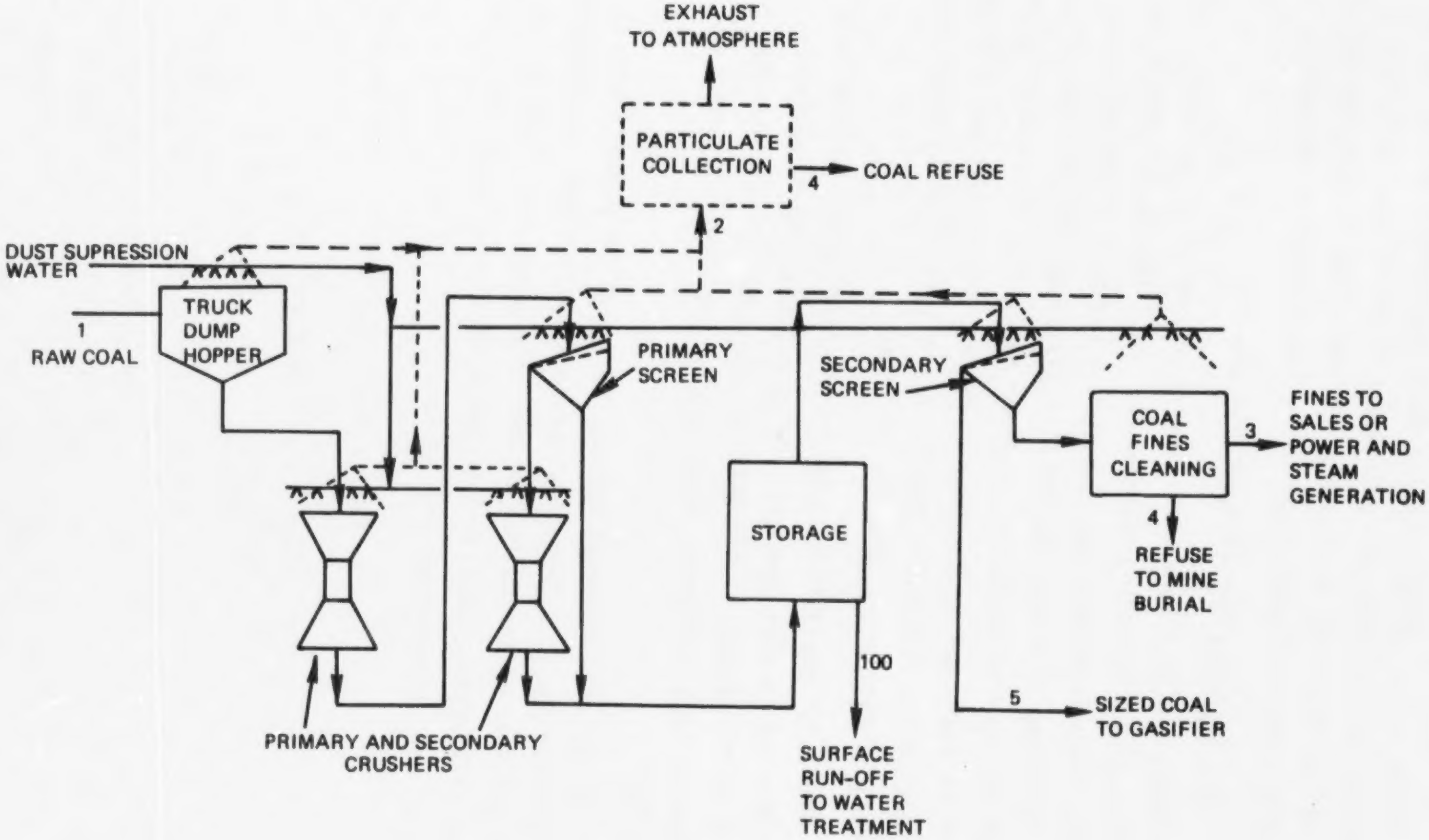
EXHAUST TO ATMOSPHERE
PARTICULATE COLLECTION
4
COAL REFUSE
2
DUST SUPRESSION WATER
1
RAW COAL
TRUCK DUMP HOPPER
PRIMARY SCREEN
SECONDARY SCREEN
COAL FINES CLEANING
3
FINES TO SALES OR POWER AND STEAM GENERATION
4
REFUSE TO MINE BURIAL
STORAGE
100
5
SIZED COAL TO GASIFIER
PRIMARY AND SECONDARY CRUSHERS
SURFACE RUN-OFF TO WATER TREATMENT

Figure 2-5. Flow Diagram for a Typical Lurgi SNG Coal Preparation Operation (stream numbering system is consistent with those shown in Figures 2-2, 2-3 and 2-4)

coal storage pile. Water used for dust suppression is usually small in quantity and becomes part of the coal moisture content without producing a net runoff. Solid wastes from coal preparation include fines from screening (Stream 3), dust from particulate collection and coal cleaning refuse (Stream 4).

2.2.3 Coal Gasification (Figures 2-2 and 2-6)

Figure 2-6 is a schematic diagram of the Lurgi gasifier. The gasifier consists of the following components: coal lockhopper, water jacketed pressure gasifier, ash lockhopper and ash quench system. Sized coal from coal preparation is stored in a coal hopper directly above the gasifier. Coal is transferred intermittently to the gasifier via a coal lockhopper pressurized with either an inert gas (e.g., CO_2) or cooled raw product gas (Stream 15). When the pressure of the lockhopper reaches a pressure slightly above that in the gasifier, the coal is discharged into the gasifier.

The Lurgi gasifier is a water jacketed vessel and features rotating blades near the top to stir the coal and counteract caking tendencies. A revolving grate at the bottom of the gasifier provides for uniform flow of ash to the ash lockhopper and introduces steam and oxygen uniformly under the downward moving coal bed.

As the coal descends through the gasifier counter-current to gas flow, it passes through four "zones" of progressively higher temperatures before exiting the gasifier at the bottom as ash. The zones are, from top to bottom, drying, devolatilization, gasification and combustion. Major chemical reactions associated with these zones are:

$$\text{Coal} + \text{heat} = C_x H_y + H_2O \text{ (drying and devolatilization)}$$

$$\left.\begin{array}{l} C + H_2O + \text{heat} = CO + H_2 \\ CO + H_2O = CO_2 + H_2 + \text{heat} \\ C + CO_2 + \text{heat} = 2CO \\ C + 2H_2 = CH_4 + \text{heat} \end{array}\right\} \text{(Gasification)}$$

$$\left.\begin{array}{l} C + 1/2O_2 = CO + \text{heat} \\ C + O_2 = CO_2 + \text{heat} \end{array}\right\} \text{(Combustion)}$$

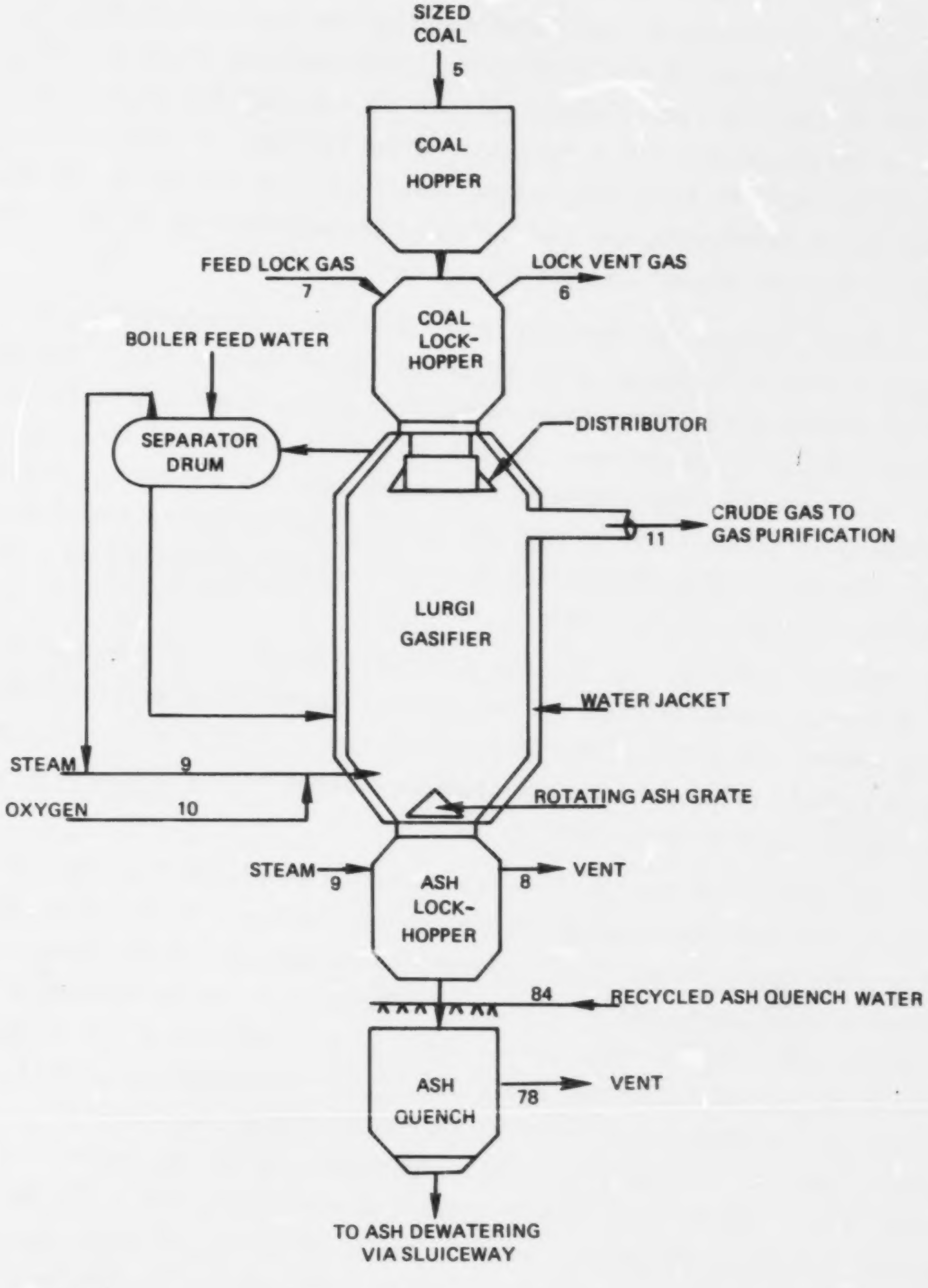
SIZED COAL
5
COAL HOPPER
FEED LOCK GAS
7
LOCK VENT GAS
6
COAL LOCK-HOPPER
BOILER FEED WATER
SEPARATOR DRUM
DISTRIBUTOR
CRUDE GAS TO GAS PURIFICATION
11
LURGI GASIFIER
WATER JACKET
STEAM
9
OXYGEN
10
ROTATING ASH GRATE
STEAM
9
ASH LOCK-HOPPER
8
VENT
84
RECYCLED ASH QUENCH WATER
ASH QUENCH
78
VENT
TO ASH DEWATERING VIA SLUICEWAY

Figure 2-6. Lurgi Gasifier

In the first zone the coal is dried by contact with the hot crude gas leaving the gasifier. As the temperature of the coal rises in the second and third zones, devolatilization and gasification occur endothermically. Combustion occurs in the fourth zone which supplies the heat for the endothermic reactions in the second and third zones. High pressure and temperature steam (Stream 9) and high purity oxygen (Stream 10) are supplied to the combustion zone of the gasifier. Steam for gasification is supplied from three sources: (1) utility boilers fired with either coal fines, low Btu gas or tar/oil, (2) water jacket surrounding the gasifier, and (3) superheating of the steam produced in the raw product gas cooling system.

The ash (Stream 12) produced in the gasifier is discharged to the ash lockhopper through a revolving grate at the bottom of the gasifier. The ash lockhopper is pressurized with steam to gasifier pressure and ash is discharged intermittently to the hopper. The ash lockhopper has a vent for pressure adjustment thus enabling free discharge of the ash into the ash quench system. Ash quenching is accomplished by spraying water (recycled quench water) on the hot ash. The ash is then transported in a water slurry (Stream 80) to a clarification and solids handling system.

The hot crude gas leaving the gasifier (Stream 11) is composed primarily of unreacted steam, methane, carbon monoxide, carbon dioxide, and hydrogen. Also present are higher molecular weight organics (e.g., tars, oils, phenols, fatty acids), reduced sulfur and nitrogen compounds (e.g., H_2S, COS, mercaptans, NH_3, HCN), and entrained dust.

Emissions from the gasification operation originate from the coal lockhopper, the ash lockhopper and the ash quench system. There are no gaseous emissions from the gasifier itself. Depending on the type of gas used to pressurize the coal lockhopper, the pressurized lockhopper gas can be handled in a number of ways. If cooled product gas is used for pressurization, the lockhopper gas can be collected, compressed and added to the raw product gas. This recycling scheme is featured in the proposed design for the El Paso plant(2). If an inert gas is used for pressurization, the lockhopper gas can be treated for particulate control and subsequently discharged to the atmosphere. This method of gas handling is featured in the proposed design for the WESCO plant whereby CO_2 from gas purification operation is used as the inert gas for lockhopper pressurization.(3) In some foreign facilities (e.g., at the SASOL, South Africa plant) where raw product gas is used for lockhopper pressurization, the gas is not recovered and is discharged in the plant stack$^{(15)}$.

The vent gas resulting from the depressurization of the ash lockhopper (Stream 8) contains primarily steam with small amounts of dust and other components of the gasifier gas. The quenching of ash also produces an off-gas (Stream 78) which contains primarily steam,* and some entrained dust, and perhaps certain volatile substances resulting from the reaction of ash with water or dissolved components of the quench water.

2.2.4 Gas Purification (Figures 2-1, 2-2 and 2-7)

As indicated in Figure 2-1, gas purification operation for Lurgi systems producing SNG consists of primary and secondary gas cooling, bulk acid gas removal and trace sulfur and organics removal. A discussion of these gas purification processes follows.

Primary and Secondary Gas Cooling. The objectives of gas cooling are to remove the condensible components of the raw gas and to reduce the gas temperature for subsequent shift conversion and acid gas treatment. Figure 2-7 shows primary and secondary gas cooling for Lurgi systems.

Primary cooling is carried out in a "washer cooler" supplied by cooled recycle gas liquor (Stream 72). The treated gas from the spray chamber passes through a vertical tube waste heat boiler producing medium pressure steam. As the raw crude gas passes through the washer cooler and waste heat boiler, moisture, tars, oils and phenols are condensed, producing a gas liquor stream (Stream 13) which is conveyed to a "gas liquor separation" unit for the separation of tar and oil from water. The gas cooling process also results in the removal of most of the dust entrained in the raw gas. The dust becomes admixed with tar in the gas liquor separation units.

To attain the desired H_2-to-CO ratio in the gas for methanation, only a portion of the gas emerging from primary cooling requires shifting. Accordingly, the gas leaving the waste heat boiler is split with one portion (Stream 15) passing through shift conversion and secondary cooling and the other (Stream 14) proceeding directly to secondary cooling. As shown in Figure 2-7, secondary

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*About one-third of the water applied to the hot ash is evaporated during ash quenching$^{(31)}$; the remaining water proceeds with the ash to the ash dewatering and solids handling system.

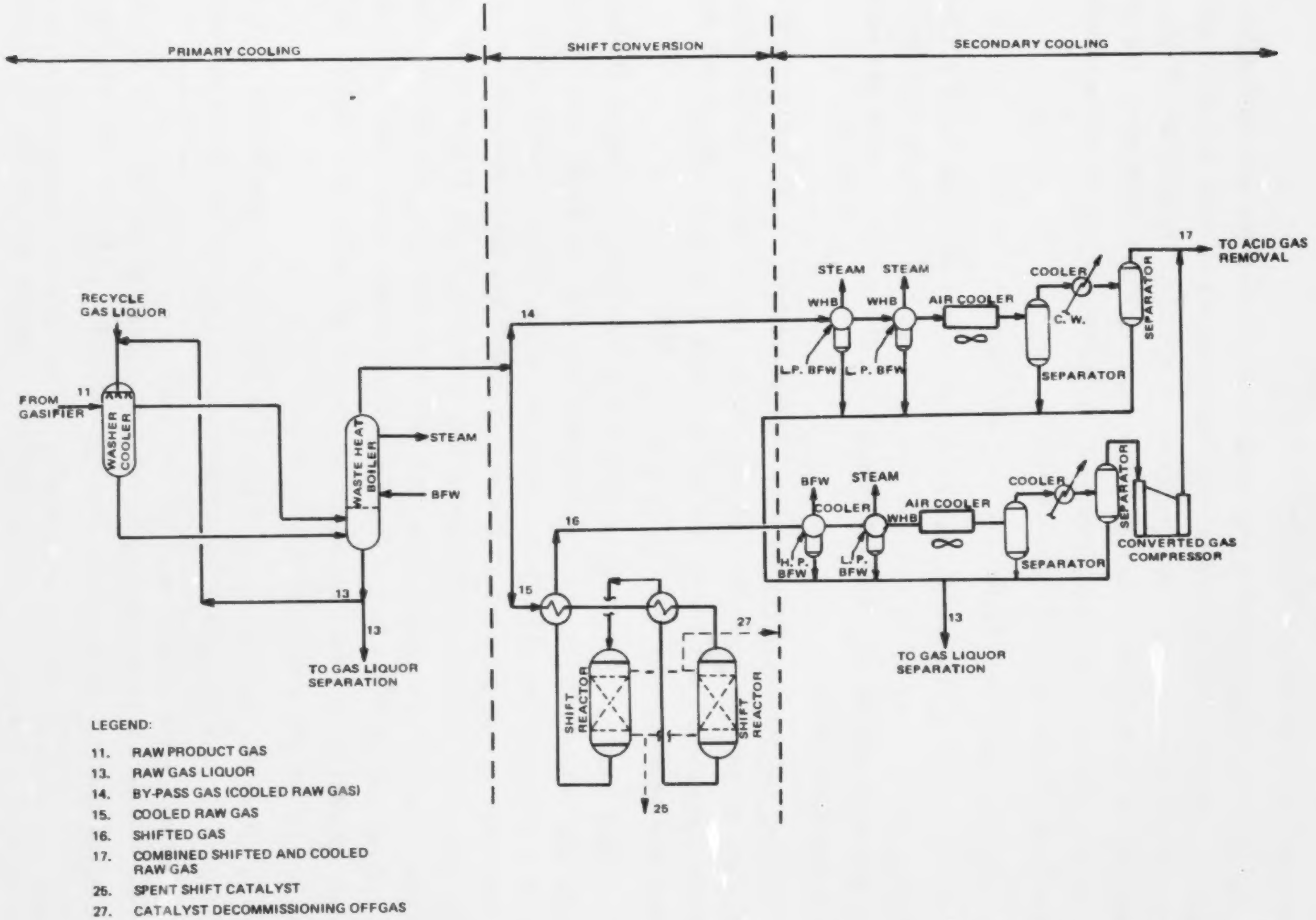
PRIMARY COOLING
SHIFT CONVERSION
SECONDARY COOLING
RECYCLE GAS LIQUOR
FROM GASIFIER
11
WASHER COOLER
WASTE HEAT BOILER
STEAM
BFW
13
13
TO GAS LIQUOR SEPARATION
14
15
16
SHIFT REACTOR
SHIFT REACTOR
25
27
STEAM
STEAM
WHB
WHB
L.P. BFW
L. P. BFW
AIR COOLER
SEPARATOR
COOLER
C. W.
SEPARATOR
17
TO ACID GAS REMOVAL
BFW
STEAM
COOLER
WHB
H. P. BFW
L. P. BFW
AIR COOLER
SEPARATOR
COOLER
SEPARATOR
CONVERTED GAS COMPRESSOR
13
TO GAS LIQUOR SEPARATION
LEGEND:
11. RAW PRODUCT GAS
13. RAW GAS LIQUOR
14. BY-PASS GAS (COOLED RAW GAS)
15. COOLED RAW GAS
16. SHIFTED GAS
17. COMBINED SHIFTED AND COOLED RAW GAS
25. SPENT SHIFT CATALYST
27. CATALYST DECOMMISSIONING OFFGAS

Figure 2-7. Primary Cooling, Shift Conversion and Secondary Cooling in Lurgi Systems(31) (stream numbers refer to master index in Table 2-7 and Figures 2-2, 2-3 and 2-4)

cooling consists of two parallel trains of waste heat boilers (which generate relatively low pressure steam), air coolers, and "trim coolers" which separate condensates from the gas. One train is for cooling of shift bypass gas, the other for shifted gas (Stream 16). After compression, the two gas streams are combined and sent to acid gas removal. Condensates produced during secondary cooling are combined with the gas liquor from primary cooling and treated for tar and oil separation.

Bulk Acid Gas Removal. The removal of H_2S and other trace sulfur compounds from combined shifted and cooled bypass gas (Stream 17) is necessary to prevent methanation catalyst poisoning. The removal of CO_2 is almost always necessary to obtain a product gas with a heating value equivalent to natural gas. The Lurgi proprietary Rectisol process for CO_2 and sulfur compounds removal, which is an integral part of the Lurgi SNG systems and is incorporated in the designs of all proposed commercial Lurgi SNG facilities, is the only acid gas removal process discussed in this document. The Rectisol acid gas removal process is based on the physical absorption of CO_2, H_2S and other compounds in cold methanol.

The solubility coefficients of various gases in methanol as a function of temperature are presented in Figure 2-8. These coefficients are the ratios of the amount of a gas found in the liquid phase to the amount of gas found in the vapor phase at equilibrium and at a gas partial pressure of 0.1 MPa (1 atm). As shown in the figure, the solubilities of the gases which are usually considered to be impurities (H_2S, COS, and CO_2) increase with decreasing temperatures while the solubilities of the desired product gases (CO, CH_4, and H_2) are not significantly affected by temperature. This indicates that the Rectisol process is more efficiently operated at low temperatures, a condition which also minimizes the solvent losses. It is for this reason that the gas feed for the Rectisol unit is precooled and refrigerated methanol is used in the process.

The following are important features of the Rectisol process in SNG production application.

- Total sulfur levels of less than 0.1 ppmv can be obtained in the treated gas
- Organic sulfur compounds such as mercaptans and thiophene and COS and CS_2 can be completely removed.

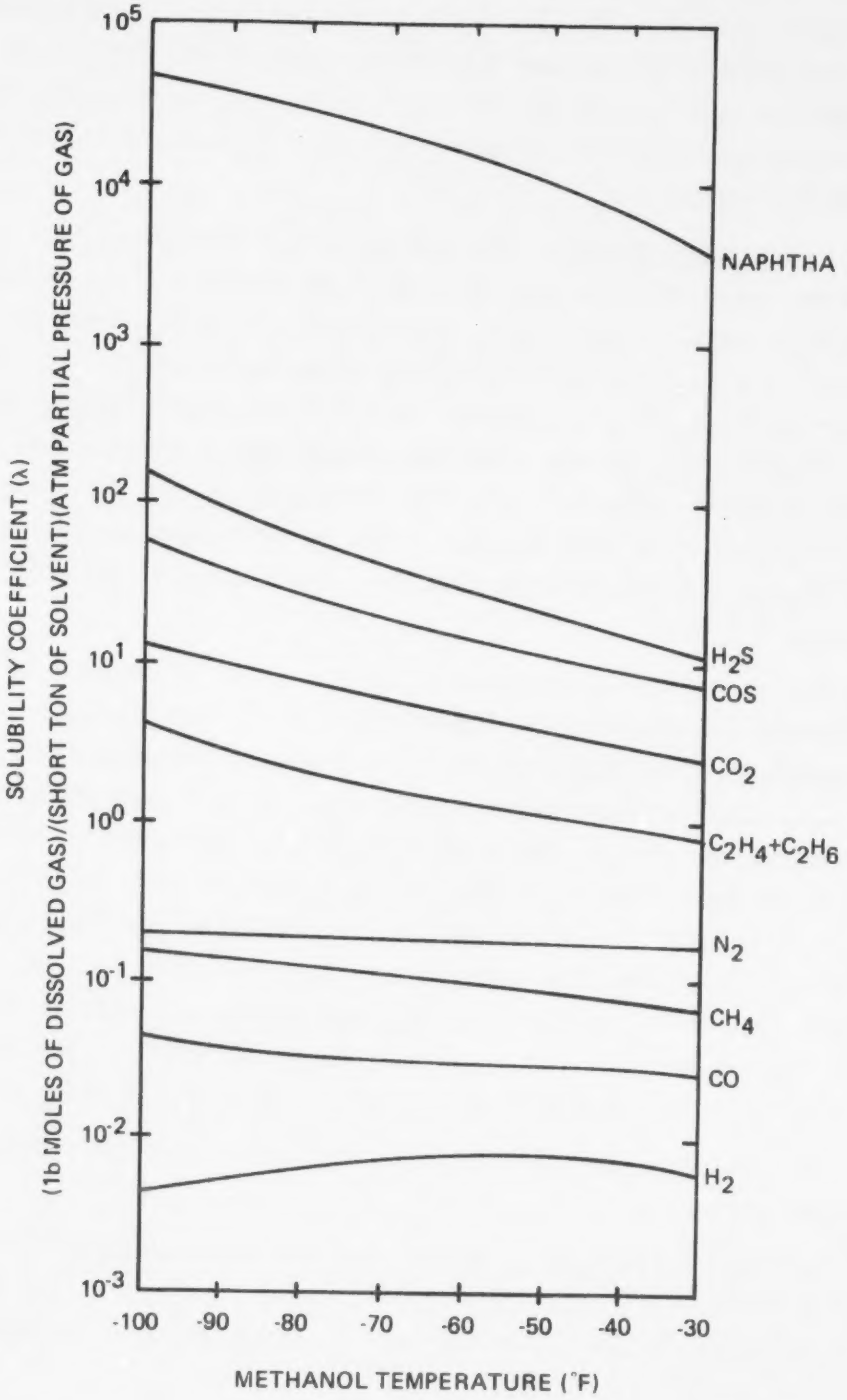

Figure 2-8. Solubility of Gases in Methanol(32)

- Process removes higher molecular weight organics which tend to form coke on the methanation catalyst and methanation guard. Sorbed organics do not degrade the solvent and are largely recovered as a naphtha byproduct.
- Traces of solvent in the treated gas do not adversely affect the downstream methanation catalyst.
- Process removes HCN.
- Process dehydrates gas, a feature which protects methanation guards and allows for somewhat smaller sized downstream gas processing units.

Depending on the feed stream characteristics and the desired concentration of H_2S in the off-gases, several design alternatives are possible for the Rectisol process. Two such designs designated as Types A and B are presented in Figures 2-9 and 2-10, respectively. In the Rectisol Type A flow scheme, feed gas enters the prewash tower where methanol rich in CO_2 and H_2S absorbs water, naphtha, ammonia and residual heavy hydrocarbons from the raw gas. The solvent exiting from the prewash column enters the prewash flash vessel where a flash stream lean in H_2S and CO_2 is produced. The liquid bottoms from the prewash flash vessel are routed to a naphtha separator where water is added to separate the naphtha fraction (Stream 20) from methanol/water by phase separation. The methanol and water are then separated in an azeotrope column and a methanol/water still with the off-gases from the latter unit routed to the hot regenerator. The regenerated methanol from the hot regenerator is cooled and recycled to the absorber where it contacts the prewashed raw gas. A slip stream of the resulting H_2S and CO_2 rich methanol is sent to the prewash column.

The bulk of the rich methanol from the absorber is flashed in several stages. The high pressure flash gas (Stream 21) is rich in higher heating value compounds and is either used as fuel or recompressed and added to the inlet raw gas. Flash gases from the other stages (Stream 22) are predominantly CO_2 and H_2S and are combined with the off-gases from the prewash flash and routed to sulfur recovery. After flash regeneration, the bulk of the methanol is returned to the middle section of the main absorber. The balance of the methanol is regenerated further in a hot regenerator to remove the last traces of absorbed gases. The hot regenerated methanol is returned via cross-exchange to the top section of the main absorber and the liberated sour gas (Stream 23) from the hot regenerator sent to sulfur recovery.

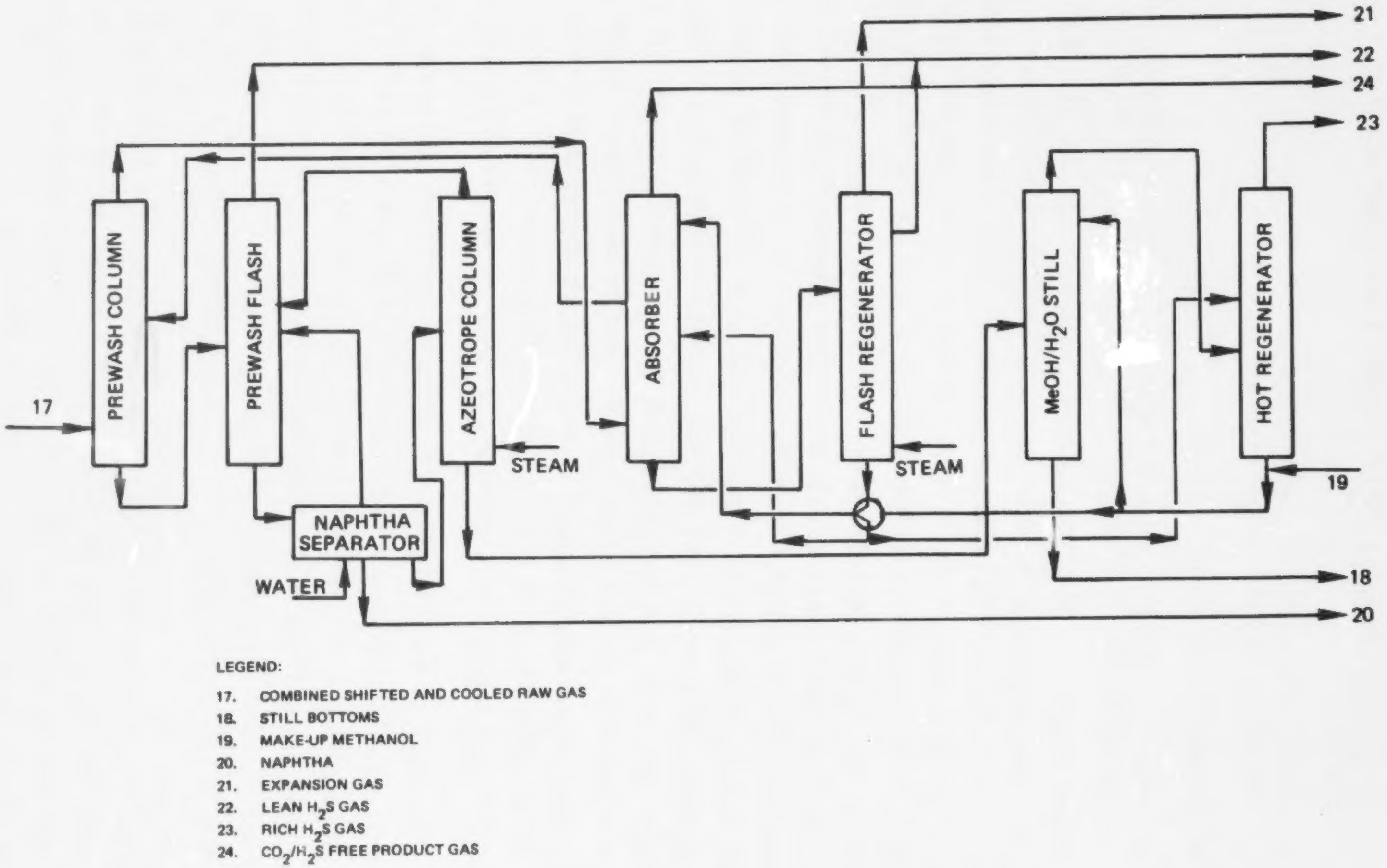
PREWASH COLUMN
PREWASH FLASH
AZEOTROPE COLUMN
ABSORBER
FLASH REGENERATOR
MeOH/H_2O STILL
HOT REGENERATOR
NAPHTHA SEPARATOR
WATER
STEAM
STEAM
17
18
19
20
21
22
23
24
LEGEND:
17. COMBINED SHIFTED AND COOLED RAW GAS
18. STILL BOTTOMS
19. MAKE-UP METHANOL
20. NAPHTHA
21. EXPANSION GAS
22. LEAN H_2S GAS
23. RICH H_2S GAS
24. CO_2/H_2S FREE PRODUCT GAS

Figure 2-9. Rectisol Type A, Combined Removal of CO_2 and H_2S(29) (stream numbers refer to master index in Table 2-7 and Figures 2-2, 2-3 and 2-4)

Except for the use of a two-stage absorber and two separate flash columns, Type B Rectisol (Figure 2-10) is similar to Type A. The raw gas (after leaving the prewash absorber) is first contacted with a CO_2-saturated methanol stream. This first stage absorber removes H_2S. In the second stage a pure methanol stream removes CO_2. The methanol for the first stage comes from the second stage absorber. The two methanol streams are flashed separately to create a stream rich in H_2S (Stream 23) and a nearly pure CO_2 stream (Stream 22). Regeneration is the same as in the Type A.

Waste streams generated by the Rectisol process(es) are the concentrated acid gases and the methanol/water still bottoms. Depending on the design, three or more concentrated acid gas streams are present. These are Stream 21, which contains the bulk of the volatile organics originally in the feed gas; Stream 22, consisting of one or more individual lean H_2S streams; and Stream 23, a relatively concentrated H_2S stream.

Trace Sulfur and Organics Removal. Although most processes for acid gas treatment remove sulfur compounds to ppm levels or lower, additional measures to protect the methanation catalyst against sulfur poisoning and carbon formation are required. Trace sulfur and organics removal systems used as methanation guards are fixed beds of adsorbents which protect methanation catalysts by (1) removing traces of sulfur compounds under normal operating conditions, (2) providing for "stand-by" bulk sulfur removal capacity in case of the malfunction of the acid gas removal systems, and (3) removing olefins and aromatic hydrocarbons which can lead to carbon formation on the methanation catalyst.*

Methanation guards are of four general types: metal oxide beds (zinc, iron or nickel), metal oxide impregnated activated carbon, activated carbon, and molecular sieves. Table 2-8 summarizes the key features of various methanation guards. As indicated in the table, a ZnO bed can achieve the lowest H_2S (and COS) levels. The zinc oxide bed, however, is not regenerable and is deactivated by the presence of the moisture in the feed gas. Spent methanation catalyst (NiO), although deactivated as far as catalytic activity for methanation is concerned, has a considerable capacity for adsorption of sulfur compounds and can potentially be used as guard bed material.

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*Trace organics removal has not been featured in the designs for proposed commercial Lurgi plants, as it is assumed that the Rectisol process will provide adequate organics removal for catalyst protection.

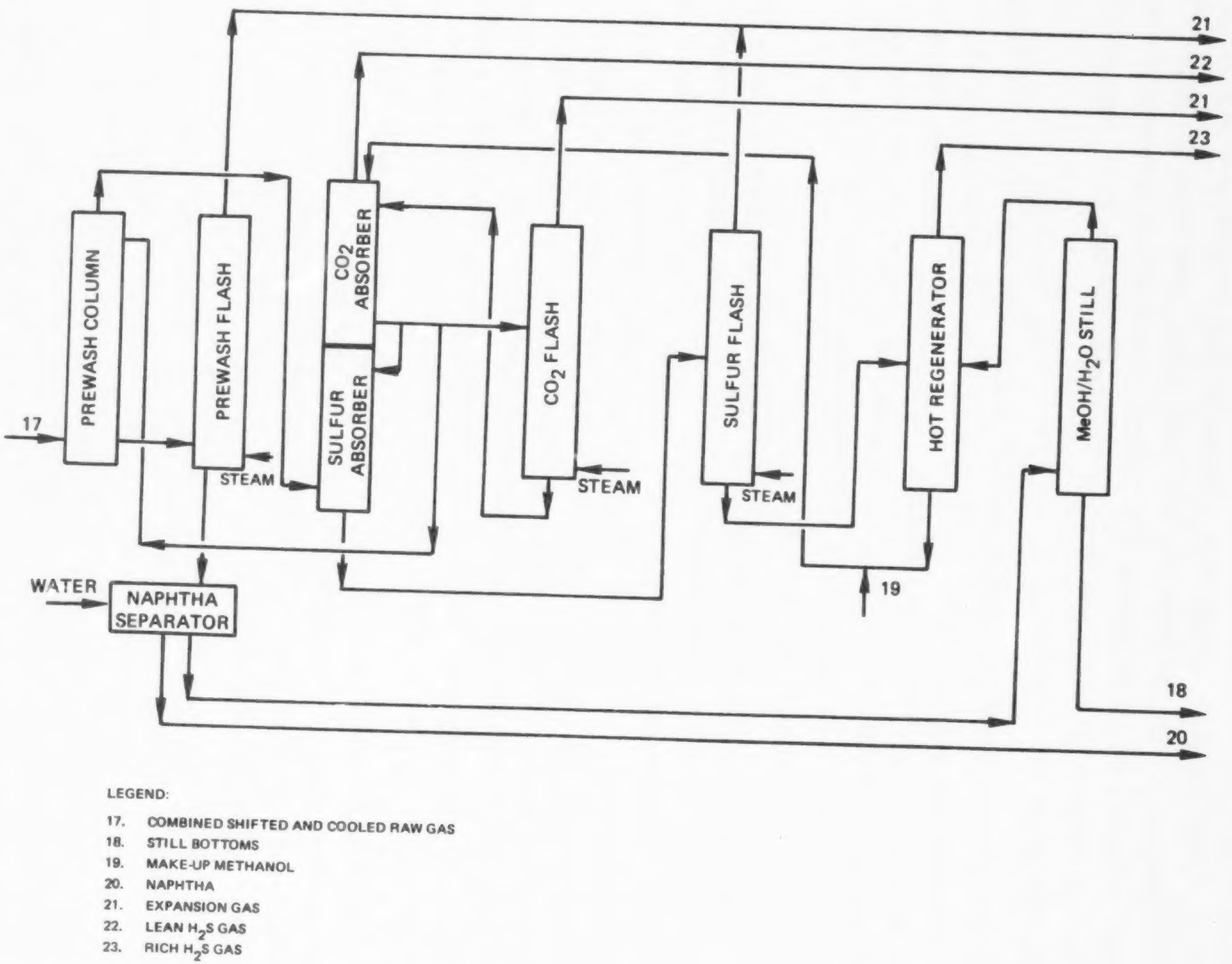
21
22
21
23
17
PREWASH COLUMN
PREWASH FLASH
STEAM
CO_2 ABSORBER
SULFUR ABSORBER
CO_2 FLASH
STEAM
SULFUR FLASH
STEAM
HOT REGENERATOR
19
$MeOH/H_2O$ STILL
WATER
NAPHTHA SEPARATOR
18
20
LEGEND:
17. COMBINED SHIFTED AND COOLED RAW GAS
18. STILL BOTTOMS
19. MAKE-UP METHANOL
20. NAPHTHA
21. EXPANSION GAS
22. LEAN H_2S GAS
23. RICH H_2S GAS

Figure 2-10. Rectisol Type B, Separate Removal of CO_2 and H_2S(29) (stream numbers refer to master index in Table 2-7 and Figures 2-2, 2-3 and 2-4)

TABLE 2-8. FEATURES OF METHANATION GUARDS

Methanation Guard	Efficiency				Applicable at High Temperature	Is Bed Regenerable	Relative Cost
	H_2S Removal	COS Removal	Organics Removal	Moisture Removal			
Metal Oxides							
ZnO	Very high	High	Low	Low	Yes	No	Low
Fe_2O_3/Fe_3O_4	High	?	Low	Low	Yes	Yes	Moderate
NiO*	High	High	Low	Low	Yes	No	Low
Metal Oxide Impregnated Carbon	High	High	High	Low	Yes†	Yes	High
Activated Carbon	Low	Low	High	Low	Yes†	Yes	High
Molecular Sieves	Moderate	Incomplete	Moderate	High	No‡	Yes	High

*Assumes the use of spent methanation catalyst as methanation guard.

†Organics may not be completely removed at high temperatures.

‡H_2S not completely removed at high temperature; moisture only partially removed at high temperature.

Metal oxide impregnated carbon offers capability for both organics and H_2S removal and can also be regenerated. The cost of the system, however, would be higher than the cost of the throw-away zinc oxide system. Activated carbon is ineffective for the removal of low molecular weight sulfur compounds (H_2S and COS) but is very effective in removing aromatics and olefins. Molecular sieves are ineffective for H_2S removal at high temperatures, but are effective for removing moisture.

In summary, ZnO appears to be the most likely candidate for trace sulfur removal applications, whereas the activated carbon and the molecular sieves are suitable for the removal of organics and moisture, respectively.

Methanation guards are essentially closed systems during routine operation, having only a feed stream (Stream 24, Figure 2-2) and a product stream (Stream 26). Periodically the guard material must be replaced and the spent sorbent (Stream 49) disposed of.

2.2.5 Gas Upgrading (Figures 2-1 and 2-2)

Although a considerable amount of methane is formed directly in the Lurgi gasifier,* hydrogen and carbon monoxide still represent the bulk of the combustible components of the raw product gas. To upgrade the gas to pipeline quality requires conversion of hydrogen and carbon monoxide to methane and this requires an H_2/CO ratio of three or greater in the gas prior to methanation. The required H_2/CO ratio is achieved by catalytic shifting. This section discusses catalytic shifting and methanation processes proposed for use with Lurgi SNG systems.

Shift Conversion. Shift conversion involves reacting CO and water vapor in the gas to produce hydrogen and carbon dioxide ($CO + H_2O = CO_2 + H_2$ + heat). To achieve the required 3:1 H_2/CO ratio, catalytic shifting may be accomplished using one of the following two approaches: (1) sending the entire gas flow through the catalytic reactor and (2) sending a portion of the flow through the catalyst bed and combining the shifted and unshifted gases afterward to obtain the proper H_2/CO ratio. Based on equilibrium calculations (and actual operating experience) a H_2/CO ratio of up to 10:1 can be obtained at about 550°K (530°F). As a consequence, it appears desirable to use the second approach for more reliable final composition control and for cost savings associated with smaller reactor size. In Lurgi SNG designs only about 50% of the raw gas is shifted.

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*Most Lurgi systems are designed to produce about 40% of the final methane content of the gas in the gasifier.

Although the shift conversion reaction can be promoted by a variety of catalysts, for the following three reasons the cobalt molybdate-based catalysts are the preferred catalysts:

(1) The catalyst is active at a high temperature (550°K or 530°F), thus eliminating excessive gas cooling prior to shifting.

(2) The catalyst can tolerate sour gas components such as H_2S and COS. This tolerance eliminates the need for H_2S removal prior to shifting. Acid gas treatment can follow shifting thus avoiding an additional acid gas removal step for the removal of CO_2 produced in the shift reaction.

(3) The catalyst also promotes the reduction of the organic sulfur in the gas naphtha to H_2S and the hydrolysis of HCN to NH_3.

The basic shift conversion equipment usually consists of two fixed bed reactors (used in series) and feed stream heat exchangers, as shown in Figure 2-7. The second reactor serves as a polishing unit and a reserve for the first reactor when the catalyst in the first reactor becomes deactivated.

The only waste streams generated in shift conversion are the spent catalyst (Stream 25, Figure 2-2) and the catalyst regeneration off-gas (Stream 27). Regeneration consists of controlled air oxidation of deposited carbon. Under ordinary service and when the catalyst is regenerated once every few months, a catalyst life of 2 to 5 years would be expected.

Methanation and Drying. The final steps in the production of pipeline quality gas are methanation and drying. Methanation involves the catalytic reaction of carbon oxides and hydrogen to form methane (and water):

$$3\ H_2 + CO = CH_4 + H_2O + \text{heat}$$

$$4\ H_2 + CO_2 = CH_4 + 2H_2O + \text{heat}$$

Methanation reactions are carried out at temperatures of 590°K to 760°K (600°F to 900°F) and at a high pressure (about 7 MPa or 1,000 psia). Figure 2-11 shows a flow diagram for the methanation process featured in the proposed designs for the U.S. commercial Lurgi SNG facilities. The process operates by passing the feed gas (Stream 26) over a fixed bed of pelleted nickel catalyst. Depending on the feed gas composition and the specific design of the methanator for temperature control/heat recovery, the feed gas to the methanator may be diluted with steam or recycled gas. A second stage methanator is employed to

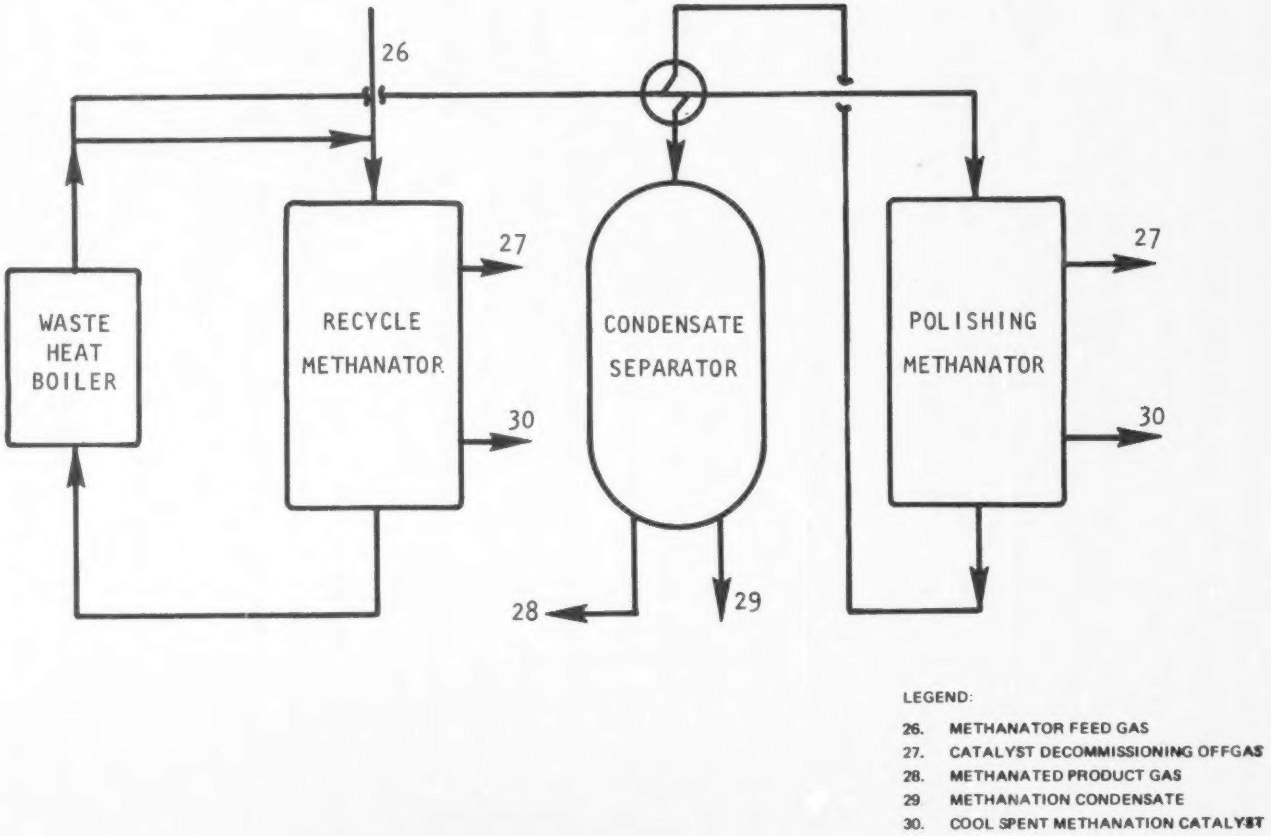
26
WASTE HEAT BOILER
RECYCLE METHANATOR
27
30
CONDENSATE SEPARATOR
28
29
POLISHING METHANATOR
27
30
LEGEND:
26. METHANATOR FEED GAS
27. CATALYST DECOMMISSIONING OFFGAS
28. METHANATED PRODUCT GAS
29 METHANATION CONDENSATE
30. COOL SPENT METHANATION CATALYST

Figure 2-11. Flow Diagram for Fixed Bed Methanation Process (stream numbers refer to master index in Table 2-7 and Figures 2-2, 2-3 and 2-4)

remove any unreacted CO, CO_2 and H_2. The methanated gas (Stream 28) is then cooled in a waste heat boiler to produce steam.

Drying of the methanated gas is usually accomplished in two stages: condensation for bulk moisture removal and sorption for the removal of residual moisture. The bulk moisture removal is achieved by cooling and heat recovery. Molecular sieves or solvents (e.g., ethylene glycol) are used for the removal of trace moisture which remains after cooling; the molecular sieves and the solvents are regenerated and reused. The gas drying operations (condensation and trace moisture removal) are not unique to SNG production and are widely used in a number of other industries (e.g., natural gas purification).

In the methanation and drying processes, three types of waste streams are encountered: (1) condensed moisture (Streams 29 and 31), (2) emissions from catalyst decommissioning (Stream 27; see below); and (3) spent catalyst (Stream 30). Condensates formed by cooling of methanator product gas are generally free of dissolved and suspended solids and gases such as H_2S and NH_3, and are therefore suitable for boiler feed water or other uses where high quality water is required.

From an environmental standpoint, the major hazards associated with catalytic methanation arise during transient operations. At temperatures less than 480°K (400°F), carbon monoxide can react with reduced nickel catalyst to form nickel carbonyl. Methanation is ordinarily conducted at temperatures above 590°K (600°F); however, temperatures of less than 480°K (400°F) are encountered during start-up and shut-down. Inert gas (e.g., N_2, CO_2) must be used during heating and cooling to exclude carbon monoxide from the bed. Since reduced nickel catalyst is pyrophoric, a spent bed is commonly decommissioned by slowly adding air or oxygen to the cooled catalyst to initiate oxidation. The controlled oxidation of spent catalyst may result in an off-gas containing particulate matter, sulfur compounds, organometallic compounds and carbon monoxide. "Burned" catalyst, although chemically more stable, still presents a hazard due to the potential toxicity of nickel. As noted previously, one likely use of oxidized spent catalyst is as methanation guard for sulfur removal.

2.2.6 Auxiliary Processes (Figures 2-3 and 2-4)

Auxiliary processes associated with the production of SNG at an integrated commercial Lurgi facility fall into two categories: pollution control processes used for the management of gaseous, liquid and solid wastes and non-pollution control support processes such as steam and power generation, oxygen production and raw water treatment. A brief description of these auxiliary processes follows.

Air Pollution Control. The two major types of gaseous waste streams associated with Lurgi SNG facilities are the concentrated acid gases (Streams 22, 23, 69, and 81, Figure 2-3) and flue gases from on-site steam and power generation (Stream 64, Figure 2-4). Depending on the sulfur content of the acid gases, treatment would consist of sulfur recovery in a Claus unit followed by tail gas sulfur removal or in a Stretford unit followed by incineration. As will be discussed in Section 4.2, hydrocarbon removal/H_2S enrichment may be necessary for acid gases treated in a Claus plant. Flue gases from combustion of coal or gasification by-products (tars, oils, phenols) would be treated for particulate removal using electrostatic precipitators or fabric filters and for SO_2 removal by one of several commercial flue gas desulfurization processes (e.g., Chiyoda Thoroughbred 101, Wellman Lord, limestone).

Gaseous waste streams of less volume and significance than concentrated acid gases and flue gases include lockhopper vent gases (Streams 6 and 8), transient waste gases (Stream 102), catalyst decommissioning off-gases (Stream 27), coal crushing and screening off-gases (Stream 2), and by-product storage vent gases (Stream 101). In the case of lockhopper vent gases, a combination of recompression/recycle and particulate control (scrubbing or use of fabric filters) prior to atmospheric discharge would be employed. Transient waste gases would be incinerated in a flare prior to discharge. Catalyst decommissioning/regeneration off-gases may require incineration and/or particulate removal before discharge. Dust from coal preparation operations would be controlled by water sprays and fabric filters. Evaporative emissions from by-product storage are controlled by use of floating roofs on storage vessels, vapor recovery systems, or incineration.

Water Pollution Control. Figure 2-3 identifies the major wastewater streams and wastewater treatment processes/modules in Lurgi SNG facilities. The condensed liquors generated during the primary and secondary gas cooling are generally combined (Stream 13) and sent to a Lurgi proprietary gas liquor separation system (see Figure 2-12) where tars and oil are separated from the aqueous phase by gravity separation. As the gas liquor passes through expansion vessels, dissolved gases are flashed off by pressure reduction and the resulting gas bubbles enhance tar/oil separation by the flotation principle. The gas liquor then flows through primary and secondary separators where quiescent settling occurs and the bulk of the tar and oil are recovered. The expansion gas (Stream 69) from the pressure reduction step contains ammonia, H_2S, and low molecular weight organics and would ordinarily be combined with other sour gases in an integrated facility for by-product recovery/pollution control. The bulk of the clarified gas liquor is recycled to the primary cooling circuit, with the excess (Stream 72) proceeding to the Phenosolvan unit for phenol recovery.

The Phenosolvan process, shown in Figure 2-13, is a proprietary Lurgi process. The gas liquor is first filtered and fed to a mixer-settler where it contacts a lean organic solvent (commonly butyl acetate or isoproyl ether). After solvent-water phase separation, the solvent is sent to a distillation column for solvent recovery. The lean solvent from the column returns to the mixer-settler while crude phenol is fractionated for purification and additional solvent recovery.

The raffinate from the mixer-settler is stripped of solvent with nitrogen gas in a packed tower and is sent to ammonia recovery. Solvent rich nitrogen gas is then contacted with scrubbing phenol from the crude phenol stripper to recover most of the solvent. Phenolic vapors remaining in the N_2 gas are then largely removed via contact with a portion of the feed wastewater. The clean gas returns to solvent recovery scrubber and the feed wastewater proceeds to the mixer settler. The Phenosolvan process generates a crude phenol product (Stream 77), a filter backwash liquor (Stream 76), a dephenolized gas liquor (Stream 75) containing traces of the extraction solvent, and a spent filter media (Stream 55).

Dephenolized gas liquor (Stream 75) contains dissolved gases such as H_2S, CO_2 and ammonia. Removal of the dissolved gases can be effected by steam stripping or by contact with an absorbing medium. The most common dissolved gas removal process is steam stripping. If necessary, the pH of the raw water is adjusted using an acid or an alkali to improve stripping efficiency. Some Lurgi plants feature the use of the proprietary Linz-Lurgi process for ammonia recovery(4). The licensed Linz-Lurgi process steam strips the gas liquor at a

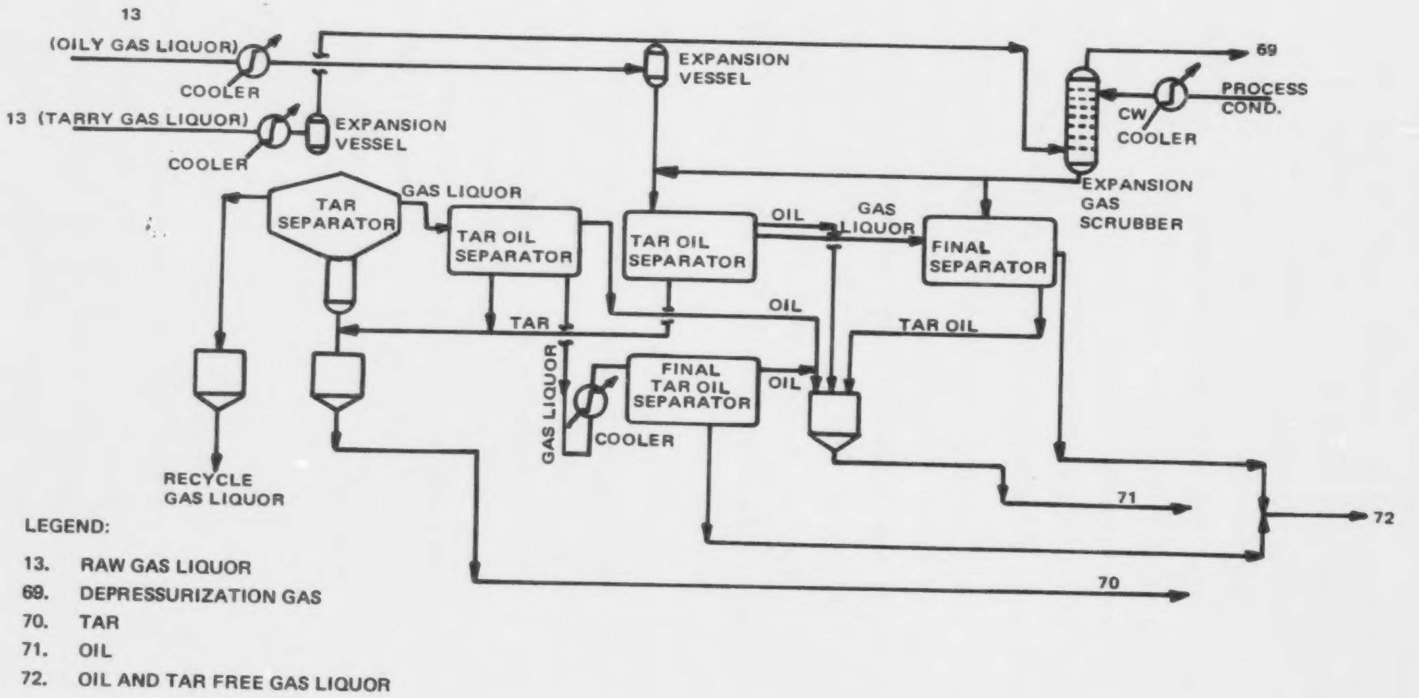
13
(OILY GAS LIQUOR)
COOLER
13 (TARRY GAS LIQUOR)
COOLER
EXPANSION VESSEL
EXPANSION VESSEL
69
PROCESS COND.
CW
COOLER
EXPANSION GAS SCRUBBER
TAR SEPARATOR
GAS LIQUOR
TAR OIL SEPARATOR
TAR OIL SEPARATOR
OIL
GAS LIQUOR
FINAL SEPARATOR
TAR
OIL
TAR OIL
GAS LIQUOR
FINAL TAR OIL SEPARATOR
OIL
COOLER
RECYCLE GAS LIQUOR
71
72
70
LEGEND:
13. RAW GAS LIQUOR
69. DEPRESSURIZATION GAS
70. TAR
71. OIL
72. OIL AND TAR FREE GAS LIQUOR

Figure 2-12. Flow Diagram for a Typical Lurgi Gas Liquor Separation System(31) (stream numbers refer to master index in Table 2-7 and Figures 2-2, 2-3 and 2-4)

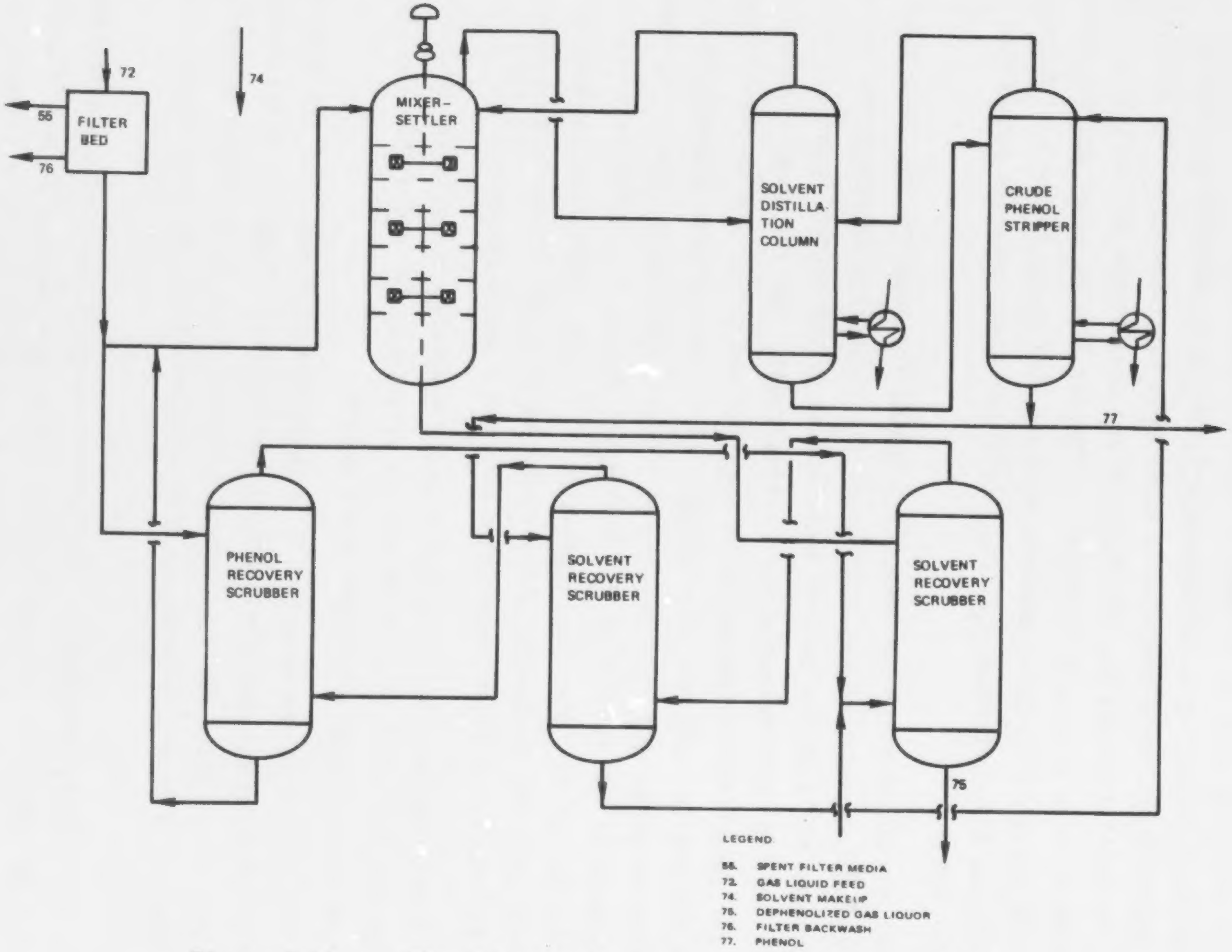
72
55
76
FILTER BED
74
MIXER-SETTLER
SOLVENT DISTILLATION COLUMN
CRUDE PHENOL STRIPPER
77
PHENOL RECOVERY SCRUBBER
SOLVENT RECOVERY SCRUBBER
SOLVENT RECOVERY SCRUBBER
75
LEGEND
55. SPENT FILTER MEDIA
72. GAS LIQUID FEED
74. SOLVENT MAKEUP
75. DEPHENOLIZED GAS LIQUOR
76. FILTER BACKWASH
77. PHENOL

Figure 2-13. Flow Diagram for Phenosolvan Process (33)

controlled pH of about 5.0 thus tying up the ammonia as a salt in solution. The acid gases (CO_2 and H_2S) are stripped off in a stripping tower and the stripped liquor is sent to an ammonia stripper where ammonia is stripped off and condensed, producing a 25% ammonia solution as a saleable by-product. Two other patented processes potentially applicable for recovery of the ammonia in Lurgi SNG facilities are the USS Phosam W and the Chevron WWT processes. These processes will be discussed in detail in Chapter 5. The major waste stream generated by steam stripping/ammonia recovery operations is the stripper overheat (Stream 81) containing H_2S, CO_2, and other steam volatile substances (e.g., phenols, HCN).

Two approaches which are commonly proposed for handling the clean gas liquor from ammonia removal/recovery units are: (1) biological treatment and the use of the treated effluent for cooling tower makeup or ash quenching and (2) direct use as cooling tower makeup without pretreatment. Cooling tower blowdown is used for quenching/transportation of gasifier and boiler ash to clarifier units, where the ash is separated as a sludge. Clarifier effluent proceeds to settling/evaporation ponds where all or part of the wastewater evaporates. The designs for commercial SNG facilities for New Mexico incorporate solar evaporation for the disposal of all the plant wastewater(2,3). For facilities in Wyoming and North Dakota, the wastewater which cannot be disposed of via solar evaporation will be treated by flash evaporation with fresh water recovery(14,15).

Plant site and coal pile runoff would generally be collected by a sewer system and the water treated by gravity separation for use within the plant as cooling tower and/or ash quench water makeup.

Relatively saline waters will be generated as a result of raw water treatment (softening and demineralization) and the use of flash and brine evaporators for wastewater disposal/fresh water recovery. Such brines would generally be disposed of with ash sludges, by deep well injection, or by discharge into lined evaporation ponds.

Solid Waste Management. The general types of solid wastes associated with Lurgi SNG facilities are gasifier and boiler ash (Streams 85 and 63), sludges from air and water pollution control and raw water treatment (Streams 53, 54, 55, 96, 93, and 39) and spent catalysts and sorbents (Streams 25, 30, and 48). The most commonly proposed appoach for handling and disposal of the ash and sludge is to bury these materials with re-deposited overburden in conjunction with strip mine reclamation. For some sludges, lined settling/evaporation ponds are proposed whereby the ponds eventually fill with semi-solid waste and are later covered with soil or abandoned. The more hazardous catalyst wastes may in some cases be sent to the manufacturer or to a reclaimer where the metal values are recovered. Alternatively, these materials would be disposed of in the mine or in landfills, perhaps in sealed drums and/or in isolated sections of a disposal site. Certain solid wastes, e.g., biosludges, can also be disposed of by land spreading or used as soil conditioners in strip mine revegetation. Sludges and solids with high organic contents may be incinerated with or without heat recovery.

Steam and Power Generation. The steam and power requirements for a Lurgi coal gasification facility will be dependent upon the selection of auxiliary and pollution control units and the choice of driving equipment for compressors, pumps, etc. Steam needs will be satisfied on site while power may be either purchased or generated onsite. Steam and power may be generated by burning any, some or all of the following fuels: coal, coal fines, tars, oils, and low-Btu gas from coal gasification. The fuel choice will be dependent upon fuel availability and economic considerations.

The proposed designs for U.S. commercial Lurgi SNG facilities feature different approaches to steam/power generation. The El Paso project proposes to use gas turbine generators fueled by low-Btu gas from a series of air blown Lurgi gasifiers for power generation(2). The gas turbine will drive electric generators directly, with steam generation provided by recovery of the gas turbine waste heat. The air-blown Lurgi gasifiers will have waste streams similar to those from the oxygen-blown gasifier. Low-Btu gas will be treated for H_2S removal prior to combustion. The primary waste stream from the gas turbines will be the combustion flue gases. Because of the clean nature of the fuel, the gas turbines operate relatively cleanly and the major pollutant is expected to be NO_x. No liquid or solid discharges are associated with the use of gas turbine-generator units. Comparison of emissions from this source with other alternatives for steam and power generation (e.g., direct combustion of coal) must include emissions from the low-Btu gasification step.

The ANG Coal Gasification Project calls for onsite steam generation but purchase of electricity from a utility company(15). The steam generation will be through the use of waste heat boilers and the combustion of tars, oils, phenols and naphtha from the gasification process. Waste streams will be those commonly associated with liquid fuel-fired steam boilers.

The WESCO gasification project also calls for the purchase of electricity(3). Coal fines, however, will be used to fire boilers for steam generation. Waste streams from these boilers will include: flue gas (containing particulates, SO_2, HC, CO), ash and sludges from pollution control devices employed (e.g., electrostatic precipitators or flue gas desulfurization units).

The sponsors of the Dunn County, North Dakota, project and the Wyoming Coal Gasification Project envision onsite steam and power generation using conventional coal-fired boilers(13,14).

Oxygen Production. Oxygen required by the Lurgi gasification system will be produced using standard air separation units. Several trains producing oxygen in the 98-99.5% purity range will be required for a commercial size gasification facility. The trains consist of air compressors, air separation units (cold box) and oxygen compressors.

The air compressors and oxygen compressors will be either steam- or electric-driven or a combination thereof. The air separation unit cryogenically separates the oxygen and nitrogen. The sole discharge streams will be the waste nitrogen and cooling tower blowdown. The proposed design for the El Paso plant features the use of a small portion of the nitrogen for pressurization of the feed lockhoppers of gasifiers used for fuel gas production(2).

Raw Water Treatment. Raw water for use in the gasification facility would be processed through various units to render the raw water suitable for use as boiler feed water (BFW), cooling tower makeup water and as potable water. The degree of treatment depends upon the characteristics of the raw water at each gasification facility. A general flow diagram for water treatment is presented in Figure 2-4.

Raw water (Stream 34) is generally treated first by coagulation and settling. The clarified water (Stream 40) is then filtered and the product water (Stream 42) is used as potable water (after chlorination) or further treated by ion exchange or chemical softening for use as boiler feedwater. Water condensed from product SNG in the methanation and drying section (Streams 29 and 31) which is relatively free of dissolved solids, is also used as a supplementary source of boiler feed water after the removal of dissolved gases by depressurization. (The depressurization off-gas is commonly added to product SNG.) In the designs for the El Paso Burnham and ANG coal gasification facilities, boiler feed water is supplied from two different sources: (1) zeolite softened water for low pressure boilers and (2) demineralized water for low pressure boilers(2,15).

Waste streams from raw water treatment are filter backwash (Stream 41), coagulation/settling sludges (Stream 39) and demineralizer brines/chemical softening sludges (Stream 49).

2.3 PROCESS AREAS OF CURRENT ENVIRONMENTAL CONCERN

Currently a major fraction of the natural gas in the U.S. is used in heating applications. If electricity produced via coal combustion or SNG were to replace natural gas in these applications, essentially the same amount of coal would have to be mined to produce an equivalent amount of end use energy. The environmental problems associated with coal mining and ash disposal would be comparable for the two methods of coal utilization. Since one of the major motivations for producing SNG from coal is to avoid the air pollution problems associated with direct coal combustion, it is essential that SNG plants themselves are not major sources of pollution and that the pollution problems are not merely being displaced from one location or media to another. For this reason it is necessary that the commercial SNG facilities be designed and operated in a manner that pollution displacement is avoided. This section summarizes the environmental areas of concern associated with the process/operations discussed above.

2.3.1 Coal Pretreatment and Handling

As noted in Section 2.2.2, the major waste streams associated with the coal preparation operation are fugitive dusts, coal refuse and runoff from coal piles. These wastes, however, are not unique to Lurgi SNG systems and methods for their control (e.g., use of sprays for dust supression or collection and use of the coal pile runoff as process water) have been well established and are used wherever coal is mined/processed. In a Lurgi SNG facility, these wastes are not especially large in quantity or very hazardous in nature. Compared to a coal preparation operation for a utility boiler, considerably smaller quantities of dusts requiring controls are generated in a Lurgi SNG facility, since larger size coals are fed to the Lurgi gasifier and hence a smaller degree of crushing is required. New Source Performance Standards and Effluent Guidelines are already in existence for coal preparation facilities. Coal preparation in Lurgi SNG facilities is not expected to be a process area of major environmental concern.

2.3.2 Coal Gasification

As discussed in Section 2.2.3, only two types of wastes are generated in the gasification operation. These are lockhopper (feed and ash) vent gases and gasifier ash. Although compared to other gaseous emissions in a Lurgi SNG facility, the total volume of the lockhopper vent gases is small, these streams will require control before discharge. The lockhopper gases are expected to contain particulates, hydrocarbons, carbon monoxide and reduced sulfur and nitrogen compounds. Essentially no data have been published on the characteristics of these gases from an operating gasifier (including their hazardous properties) or on the effectiveness and costs of the various controls proposed for use in gasification facilities. The small amount of data which is available on gross characteristics and leachability of Lurgi ash is limited in that (a) the data have been obtained on coals other than those proposed for use in commercial SNG facilities in the U.S., and (b) the data are for laboratory conditions and not necessarily reflective of conditions which would be expected in commercial plants (e.g., use of plant wastewaters for ash slurrying). Based upon the available data, except for its larger particle size, for a given coal the Lurgi ash would be very similar to coal combustion boiler and fly ash in terms of gross physical and chemical properties.

2.3.3 Gas Purification

Quenching and cooling of the Lurgi raw product gas produce a gas liquor which is the major aqueous waste in the gas purification operation. Although this waste stream is well characterized in terms of gross properties and content of major constituents, relatively little data are available on specific organic substances and trace inorganics in this waste stream and on the fates of these substances in the proposed downstream treatment systems (e.g., Phenosolvan, ammonia recovery, biological treatment and ash quenching).

The concentrated acid gases which result from gas purification in the Rectisol process is one of the two major potential sources of atmospheric emissions in a commercial Lurgi SNG facility. (The second major source is flue gases from onsite power and steam generation - see Section 2.3.5.) Concentrated acid gases from the Rectisol process contain primarily CO_2 and the bulk of the original coal sulfur in the form of H_2S and to lesser extent COS, CS_2 and mercaptans. These acid gases also contain some low molecular weight organic compounds, CO and HCN. Without pollution control, sulfur compounds in acid gases could represent up to 90% of total sulfur emissions from a Lurgi facility and nearly 100% of the CO and HC emissions. However, with pollution control systems proposed for commercial SNG projects, acid gases represent only a small fraction of total plant sulfur emissions. The CO and HC contribution to the plant total from treated acid gases is much larger than in the case of sulfur emissions. Acid gases are not significant sources of NO_x or particulate emissions.

The available data for the Rectisol acid gas treatment process are not very comprehensive in that all streams and constituents of environmental interest are not addressed. The data are also for foreign installations which differ in design and operating characteristics from those proposed for U.S. SNG facilities; such differences in designs are likely to impact stream flow and composition. In particular, the Lurgi product gas feed to the Rectisol unit needs to be characterized in terms of trace constituents, and the fate of such constituents in the particular Rectisol designs proposed for U.S. facilities needs to be defined. Three environmentally important constituents in the feed and off-gases are COS, HCN and HC. The levels of these constituents in the off-gases determine the type and extent of downstream pollution control systems which would be required.

2.3.4 Gas Upgrading

The only continuous waste stream produced in the gas upgrading operation is the methanation condensate. As noted previously, this condensate is expected to be very clean and would be used in the plant as boiler feed water. The catalysts used for shift and methanation (as well as the methanation guards), however, require periodic replacement. Very little information has been published on the service life of these catalysts or on the characteristics of the spent materials. Because of their expected hazardous characteristics, proper handling, disposal, or reuse of spent catalyst is a major area of environmental concern.

Gaseous waste streams are generated as a result of decommissioning/regeneration of spent catalysts. Although of intermittent nature and of relatively small volume, these gases are of environmental concern due to the potential presence of substances containing elements such as Ni, Co, Mo and Zn, in addition to CO, reduced sulfur compounds and polycyclic organic material (POM).

2.3.5 Auxiliary Processes

Although many of the pollution control processes which are proposed for use in commercial Lurgi SNG facilities have been tested or used commercially in other industries, their performance in SNG service has generally not been evaluated. For example, the Stretford process, which has been used comercially for the treatment of natural gases and coke oven gases, has not been evaluated for the treatment of high CO_2 content Rectisol off-gases. (It is only recently that a commercial Stretford unit has been placed in such service at the SASOL Lurgi plant in South Africa)$^{(34)}$. Similarly, the performance of commercial sulfur recovery tail gas treatment processes such as the Beavon process for handling high CO_2 gases from the Stretford or Claus plant has not been evaluated. Incineration is proposed for the control of hydrocarbon emissions in the Rectisol off-gases. Since this method of control requires supplemental fuel, the trade-offs between the degree of emission control, energy penalty and the impact on the economics of SNG production have not been established.

With respect to water pollution control, the areas of major environmental concern relate to the lack of adequate data on the characteristics of wastewaters produced in an integrated Lurgi SNG plant and on the effectiveness of various proposed treatment processes for the removal of specific pollutants from these wastewaters. In general, much of the available wastewater characterization data which have been reported are for gross properties (TOC, COD, etc.) and major constituents (e.g., phenols, ammonia, sulfide, etc.); less data are available on trace elements, organics and environmental and health effects. The specific areas of ecological concern which need to be addressed relate to the biodegradability, bioaccumulability and the environmental persistence of the constituents in various aqueous waste streams in a Lurgi SNG plant. Although phenol and ammonia recovery and biological treatment (e.g., using the activated sludge or cooling tower oxidation processes) are expected to result in some removal of many of the troublesome substances (e.g., CN^-, SCN^-, POM, Hg, As, Cd), actual operating data are not available to indicate the expected residual levels in treated wastewaters.

All proposed commercial Lurgi SNG plant designs feature "zero discharge" of plant wastewaters to surface waters. This is to be achieved by a combination of solar evaporation in ponds and forced evaporation using fuel. Two questions arise from an examination of the "zero discharge" concept as applied to Lurgi plants. First, solar and forced evaporation may solve the problem of bulk wastewater disposal but leave a residue (sludge or brine) disposal problem. Unless properly designed and operated, ponds may also constitute an indirect discharge source to surface or groundwaters via leakage or infiltration. Secondly, the practicality of "zero discharge" for SNG plants in the eastern U.S. is not well established. With relatively inexpensive raw water readily available, there would be less incentive for minimum water use and hence wastewater generation. Furthermore, solar evaporation is not practical east of the Mississippi River and hence, expensive forced evaporation (or other salt removal processes) would be required to meet the zero discharge goal.

Solid wastes generated by Lurgi systems include gasification and combustion ash, raw water treating and pollution control solids/sludges, and spent catalysts and related materials. Generally, the ash generated by gasification is not expected to be greatly different from ash generated by coal-fired boilers and techniques for transport and disposal of this material in SNG plants would be similar to those practiced in large coal-fired power plants. When treated gas liquor or other SNG plant wastewaters are used as ash slurry make-up water, however, ash slurries in SNG facilities may have somewhat different composition/properties than slurries encountered in coal-fired power plants. Water treating and pollution control brines and sludges from SNG plants would not be expected to be greatly different from those in other industries. When combined with gasifier ash slurries, however, the waste may have certain unique characteristics requiring evaluation before selection of an optimum treatment/disposal method. Sludge properties which would require evaluation include dewaterability, leachability and chemical reactivity. A solid waste disposal area of particular environmental concern is the disposal of spent catalysts and related materials. Such materials contain potentially toxic catalyst metals and accumulated coal-derived substances from coal (e.g., As, high molecular weight organics, and sulfur- and nitrogen-containing substances). Although the types of catalysts which are proposed for use in SNG plants have been used in other industrial applications, little is known about the properties of the spent materials and the prevailing spent catalyst handling methods, primarily due to the proprietary nature of many catalyst formulations.

The non-pollution control auxiliary processes such as raw water treatment and steam and power generation which would be utilized in commercial Lurgi SNG plants are widely used in industry, and environmental problems associated with their use in SNG plants are not considered to be unique or unmanageable.

3.0 CHARACTERIZATION OF INPUT MATERIALS, PRODUCTS AND WASTE STREAMS

This chapter is a summary of the available data relating to the physical, chemical and biological properties of input materials, products and process/waste streams associated with Lurgi systems for the production of SNG. Since no integrated commercial Lurgi SNG plant currently exists, all of the available operating/testing data are for some of the individual units/processes comprising Lurgi SNG system. These data have generally geen obtained in different locations, under different operating conditions and in connection with programs having different objectives. Since in many cases these data are fragmented and not directly comparable, these limitations should be recognized when such data are used to estimate the characteristics of streams in an integrated commercial facility.

The data presented in this chapter fall into four categories: (1) operating or testing data for the individual components of the Lurgi systems, (2) design bases for proposed commercial facilities, (3) laboratory testing data for various Lurgi products or wastes, and (4) pertinent data for similar streams from other gasification processes where Lurgi data are unavailable. Section 3.1 describes sites and equipment sampled or planned to be sampled by IERL/RTP and other organizations and the operating conditions under which samples have been or will be acquired. Sections 3.2 through 3.7 present the physical, chemical and biological effects data on a stream-by-stream basis. All materials, products and process/waste streams are referred to master flow diagrams (Figures 2-2, 2-3 and 2-4) in Section 2.2.1.

3.1 SUMMARY OF SAMPLING AND ANALYTICAL ACTIVITIES

3.1.1 IERL/RTP Environmental Assessment Activities

The Fuel Process Branch of EPA's Industrial Environmental Research Laboratory, Research Triangle Park (IERL/RTP) is currently carrying out a comprehensive assessment program to evaluate the environmental impacts of synthetic fuels from coal processes having a high potential for commercial application. The

EPA effort consists of (a) evaluation of existing process and environmental data and the data which are being generated by process developers, (b) definition of additional data needed for comprehensive environmental assessment, (c) acquisition of supplementary data through sampling and analysis of process/waste streams at selected coal conversion facilities, and (d) necessary process engineering support studies and completion of the comprehensive environmental assessment. Many of the elements of IERL/RTP programs are carried out through contract and grant services. The following is a brief description of the major IERL/RTP activities involving data collection through sampling and analysis of Lurgi or Lurgi-related process/waste streams.

Sampling and Analysis at the Kosovo Plant(35). The Kosovo Kombinant plant in Pristina, Yugoslavia is a Lurgi gasification facility which converts lignite to fuel gas and fertilizer plant feedstocks. Under a cooperative research program EPA and the Rudarski Institute (Belgrade, Yugoslavia) are involved in an environmental test program at the Kosovo plant. The EPA effort is being carried out through a contract to the Radian Corporation (Austin, Texas). A test plan which had been developed for the facility is currently being implemented. The test plan calls for sampling a total of 42 process/waste streams associated with coal transport, gasification, ash disposal, tar separation, Rectisol, Phenosolvan, by-product storage and cooling towers. The data collected in the test program are expected to become available in early 1979.

Study of Lurgi Ash(36). Illinois State Geological Survey (ISGS) has conducted studies on ash from Illinois No. 6 coal which was gasified in the Lurgi facility at Westfield, Scotland. These studies included trace element and mineralogical analyses of the unquenched ash; solubility of elements in the ash leachate at four pH values over the range 2 to 11; and aquatic toxicity studies, in which fathead minnows, *Pimephales promelas*, were exposed to ash leachates. The gasification of the Illinois coal at the Westfield facility was part of a program sponsored by the Office of Coal Research (OCR) and the American Gas Association (AGA) to test American coals at the Westfield plant, as described in Section 3.1.2.

Laboratory-scale Gasifier Tests(8,37,38). Research Triangle Institute (RTI) has initiated a parametric evaluation of pollutants from a laboratory gasifier. The program consists of three phases: screening studies, parametric control evaluations, and reaction kinetics research. The screening studies consider qualitatively and, for selected compounds, quantitatively the variety of chemical compounds produced during gasification reactions. RTI has screened a large number of different compounds as part of Phase 1. The second phase which is currently under way, examines the effect of reactor operating conditions on the pollutant production. Parameters evaluated include coal type, grind size, pretreatment methods, bed depth, temperature, pressure, steam flow rate, residence time, catalysts, and additives. Other parameters such as bed type (fixed, entrained, fluidized) and reactor type (batch, semi-batch, plug flow, mixed flow) are considered. The screening studies are now under way. Most recently, gasification tests using Illinois No. 6 coal have been conducted(39).

Large Bench-scale Gasification/Gas Cleaning Unit(8,40). North Carolina State University (NCSU) is operating a bench-scale gasification/gas cleaning unit consisting of a continuous fluidized bed gasifier; a cyclone and scrubbers for removing particulates, condensables, and soluble matter from raw synthesis gas; and an acid gas removal system. The gasifier operates at pressures up to 0.8 MPa (100 psig) with a capacity of 23 kg (50 lb) coal/h. The gasifier uses either steam-O_2 or steam-air feeds to produce 0.67 Nm^3 (25 scf/min) of product gas. The acid gas removal system is testing four solvents for the removal of acid gases: refrigerated methanol, hot potassium carbonate, monoethanolamine, and dimethylether of polyethylene glycol.

The overall objectives of the project are to characterize completely the product, waste gases and condensates from coal gasification and gas cleaning processes, and to determine how emissions depend upon various process parameters. The initial operation of the gasifier has been with a chemical grade coke. The first tests of the acid gas removal unit have been with a synthetic feed gas mixture. Future tests using subbituminous coal or lignite as gasifier feed are scheduled for May 1979.

Bench-scale Treatment of Gasification Wastewaters(8,37,38). The University of North Carolina is currently conducting a bench-scale study to evaluate the effectiveness of biological and chemical processes for the treatment of gasification and liquefaction wastewaters and to determine the environmental impacts and health effects of treated effluents. The majority of tests have been and are currently being carried out with synthetic wastewaters, although several tests have used actual wastewater from a coal gasification facility. Processes evaluated include activated sludge, coagulation and carbon adsorption. Bioassay testing (i.e., Ames cell tests and cytotoxicity tests) of the synthetic wastewaters is currently under way.

3.1.2 Non-IERL/RTP Site Evaluation

Non-IERL/RTP environmental programs relating to Lurgi SNG systems are limited to those carried out by DOE and by commercial SNG project sponsors to generate data needed for full scale designs. The most relevant of these programs are briefly summarized below.

Dunn County, North Dakota Project(13). A 7 x 10^6 Nm^3/d (250 x 10^6 scf/d) Lurgi SNG facility has been proposed by the Natural Gas Pipeline Company of America (ANG). The coal is to be mined from Dunn County lignite beds. ANG sponsored a gasification test program at the SASOL plant in South Africa and an analytical support program at the University of North Dakota to obtain engineering and environmental data for the Dunn County project. Since only a very small amount of Dunn County coal was available, coal (lignite) from a mine in nearby Mercer County, North Dakota was gasified at the commercial Lurgi plant at Sasolburg, South Africa(4). Samples of the coal, gasifier ash, oil, tar, and gas liquor were analyzed at the University of North Dakota for trace and major inorganic elements. Samples of Dunn County coal and laboratory gasification ash were subjected to proximate, ultimate, and trace and major inorganic elemental analysis. Analytical values from the SASOL tests were then extrapolated to the gasification of Dunn County coal to project the distribution of elements among the gasification product and waste streams. Leachability tests were also performed on ashes from both Dunn and Mercer County lignites. In a related program samples of gas liquors from the gasification of the South African coals were also analyzed for a wide range of constituents and tested for biotreatability.

Testing of American Coal at the Westfield, Scotland Facility(7). The American Gas Association (AGA) and the Office of Coal Research (OCR) sponsored a program to test American caking coals in the Lurgi facility at Westfield, Scotland during 1972-1974. The coals tested were: Rosebud (coarse and fine graded), Illinois No. 5 (coarse graded and simulated run-of-mine), Illinois No. 6 (coarse graded and simulated run-of-mine), and Pittsburgh No. 8 (coarse graded and simulated run-of-mine). Chemical analyses were performed on the feed coal, tars, oils, liquors, product gas, flash gas and flare gas.

Analyses of Lurgi Ash(41,42). Peabody Coal Company carried out trace element analyses on coal and ash samples from gasification tests of Illinois Nos. 5

and 6 coals at the Westfield Lurgi facility. For the purpose of comparison, split samples were also tested by the Argonne National Laboratory. The results have been used by Argonne to estimate potential trace element emissions associated with Lurgi gasification.

In a separate effort, the Oak Ridge National Laboratory (ORNL) is currently completing studies on ash from the gasification of Montana Rosebud and Illinois Nos. 5 and 6 coals at the Westfield facility. A complete physical and chemical characterization of the unquenched bottom ash is being performed, as well as throughput leaching studies which include both aquatic and terrestrial bioassays.

3.2 INPUT MATERIALS

The input materials to a commercial Lurgi SNG system were identified in Section 2.1.3 in connection with the overview of the Lurgi systems. This section presents the available data on the properties of these input materials used in various gas production operations and auxiliary processes.

3.2.1 Coal Pretreatment and Handling

A variety of coals have been tested and/or are proposed for use in Lurgi gasifiers. Table 3-1 presents the proximate and ultimate analyses of these coals where data are available. Included are trace element data as reported for specific coals tested or for coal samples from the same seam/deposit. The data in Table 3-1 indicate a wide range of moisture content, caking properties and ash and trace element contents for the coals tested. When properly designed and operated, Lurgi gasifiers can handle essentially any type of coal; the commercial projects which have been proposed to date are to use subbituminous coals or lignites as feeds. Product and waste stream composition data presented in subsequent sections will be for coals listed in Table 3-1.

3.2.2 Coal Gasification

The only inputs to the gasification operation other than sized coal are steam and oxygen. Table 3-2 presents steam and oxygen consumption rates (measured or estimated for design purposes) for the various input coals listed in Table 3-1. These consumption rates are generally specific for each coal type and gasifier design and are for conditions which maximize gasification efficiency. Oxygen used in Lurgi gasifiers is generally separated from air and contains around 1-2% N_2.

TABLE 3-1. CHARACTERISTICS OF COALS WHICH HAVE BEEN OR ARE PROPOSED TO BE GASIFIED IN LURGI GASIFIERS

Coal No.	1	2	3	4	5	6	7	8	9	10
Source of Data	(7,14,43)	(7,41)	(7,41)	(7,43)	(7,44)	(15,43)	(2)	(3)	(13,43)	(14,43)
Type/Origin	Subbituminous/ Rosebud Montana	High Volatile/ Illinois #6	Bituminous/ Illinois #5	Bituminous/ Pittsburgh #8	Bituminous/ So. African	Lignite/ No. Dakota	Subbituminous/ New Mexico	Subbituminous/ New Mexico	Lignite/ No. Dakota	Subbituminous/ Wyoming
Gasification Site/ Project Acronynm	Westfield Scotland	Westfield Scotland	Westfield Scotland	Westfield Scotland	Sasolburg So. Africa	ANG	El Paso	WESCO	Dunn County	Wyoming
Size mm (in)	6.4 - 31.8 1/4 - 1-1/4	6.4 - 31.8 1/4 - 1-1/4	6.4 - 31.8 1/4 - 1-1/4	6.1 - 31.8 1/4 - 1-1/4	--	--	--	--	--	--
Composition, %										
Moisture	24.70	10.23	11.94	4.58	8.0	35.98	16.96	12.4	38.56	28.0
Volatile Matter	29.20	34.70	35.21	37.37	--	27.21	28.88	--	27.03	32.71
Ash (dry basis)	12.9	10.1	9.2	8.1	31.6	7.42	20.77	30.3	6.84	5.58
C "	67.15	71.47	7.280	77.71	52.4	71.45	59.2	37.2	63.56	68.63
H "	4.22	4.83	4.95	5.28	2.6	4.81	4.3	3.7	4.38	4.70
O "	13.02	9.02	7.99	4.24	11.7	21.01	12.2	11.1	18.92	17.74
S "	1.45	3.13	3.56	2.64	0.43	1.26	.83	1.09	1.30	0.45
N "	1.20	1.35	1.39	1.42	1.2	1.44	1.02	1.01	0.65	0.69
HHV (as gasified) kcal/kg (Btu/lb)	4,781 (8,610)	6,370 (11,470)	6,364 (11,460)	7,468 (13,442)	5,000 (8,980)	4,020 (7,230)	4,670 (8,400)	4,720 (8,500)	3,586 (6,456)	4,920 (8,848)
Swelling No.	0	3	2.5	7.5	--	--	--	--	--	--
Caking Index	0	15	22	30	--	--	--	--	--	--
Major and Minor Elements in Coal (% moisture free whole coal basis)										
Al	1.71	1.20	0.73	1.14	4.7	0.65	--	3.2	.67	0.52
Ca	1.65	0.93	0.89	2.57	1.6	2.00	--	0.6	1.6	1.50
Cl	0.02	0.28	0.13	0.13	7.0	0.02	70 (ppm)	--	.005	0.02
Fe	0.60	1.50	2.63	0.93	1.1	0.60	--	0.9	.72	0.40
K	0.11	0.16	0.10	0.13	0.1	0.01	--	.2	.005	0.03
Mg	0.23	0.04	0.04	0.04	0.3	0.26	--	.14	.50	0.10
Na	0.02	0.060	0.89	0.022	0.2	0.42	--	0.3	.24	0.169
Si	3.09	2.45	2.24	2.01	7.9	1.0	--	7.1	2.2	0.69
Ti	0.06	0.06	0.04	0.07	--	.044	--	0.4	.03	0.06

TABLE 3-1. CONTINUED

Coal No.	1	2	3	4	5	6	7	8	9	10
Type/Origin	(7,14,43)	(7,41*)	(7,41*)	(7,43*)	(7,44*)	(15,43†)	(2)	(3)	(13,43†)	(14,43†)
Source of Data	Subbituminous/ Rosebud Montana	High Volatile/ Illinois #6	Bituminous/ Illinois #5	Bituminous/ Pittsburgh #8	Bituminous/ So. African	Lignite/ No. Dakota	Subbituminous/ New Mexico	Subbituminous New Mexico	Lignite/ No. Dakota	Subbituminous/ Wyoming
Trace Elements (ppm)										
Ag	.06	--	--	--	--	< 0.1	--	--	0.03(7)	.06 - 0.43
As	.08 - 1.2	1.0	2.0	6.7	2-5	19.7 - 30	0.1 - 3.0	1.2	10	0.57 - 1.2
B	32	132	307	5.0	100	12 - 300	60 - 150	--	63	32
Ba	87	--	--	--	--	60 - 2500	--	--	230	87
Be	.7 & .8	1.6	2.0	1.3	2-3	0.12 - 2.0	2 - 3	3.4	0.31	0.71 - 0.8
Br	20	17(7)	12(7)	23	--	1.5	100	--	1.7	--
Cd	.31 - .8	<.4(7)	--	<0.20	<.1	0.63	0.2 - 0.4	0.66	0.21	0.31 - 0.8
Ce	--	--	--	--	150 - 200	--	150 - 200	--	14	--
Co	.6 - 4	4	4	12	--	0.84 - 6.0	--	--	5	0.55
Cr	4 - 16	20	15	1.8	--	1.4 - 6.0	--	--	65	4.2 - 16.0
Cs	--	--	--	--	--	--	--	--	0.26	--
Cu	9 - 10	12	10	11	--	1.2 - 6.4	--	--	23	8.9 - 10
F	66	79	57	52	100	24 - 83	100	210	21	65 - 67
Ga	--	4.5(7)	1.9(7)	4.2	--	0.46 - 1.2	0.5 - 8.0	--		--
Ge	--	6.0(7)	9.0(7)	2.0	--	0.3 - 1.2	0.1 - 0.5	--	0.60	--
Hg	11 - .17	1.1	0.2	0.14	<.1	0.05 - 0.09	0.2 - 0.3	0.01	0.20	0.11 - 0.17
I	--	--	--	--	--	--	--	--	<0.30(7)	--
In	--	--	--	--	--	--	--	--	<0.01(7)	--
La	--	--	--	--	--	1.1	--	--	1.2	--
Li	--	--	--	--	--		--	--	--	3.6 - 15.0
Mo	2.2	7	7	1.0	--	1.2 - 1.5	--	--	22	2.2
Mn	2.8 - 3.4	20	22	12	500	12.0 - 50.0	500	--	250	2.8 - 3.4
Ni	2 - 14	14	32	20	30 - 50	1.2 - 5.9	3.0 - 30.0	--	12	1.7 - 14
P	--	29(7)	--	100	--	200(7)	--	--	131	--
Pb	.51 - 12	10	28	7.0	10 - 20	0.67 -20.0	1.4 - 4.0	5.5	54	0.51 - 12
Rb	--	--	--	--	--	0.4 - 12.0	--	--	41	--
Ru	--	--	--	--	--	0.4	--	--	--	--
Sb		0.1	0.2	0.90	<.5	0.1 - 0.12	0.3 - 1.2	0.42	0.31	0.08 - 1.5
Sc	--	--	--	--	--	<0.1 - 6.0	--	--	1.5(7)	--
Se	.33	1.3(7)	1.3(7)	1.3	0.3	1.0 - 1.3	0.1 - 0.2	0.74	0.85	0.33
Sn	0.14	--	9	--	--	0.25 - 4.0	--	--	<0.30	0.14
Sr	--	--	--	5.0	--	570 - 600	--	--	1030	--
Ta	--	--	--	--	--	--	--	--	0.05(7)	--
Te	--	--	--	--	0.23	--	--	0.20	--	--
U	.88	--	--	--	--	0.27 - 1.0	--	--	3	0.88
V	10 - 14	20	21	46	300 - 500	2.7 - 12	300 - 500	--	--	10 - 14
W	--	--	--	--		--	--	--	0.58	--
Y	--	--	--	--	--	4.0 - 6.0	--	--	--	--
Zn	2 - 8	43	200	21	--	0.6 - 12.0	1.1 - 27.0	--	11	0.23 - 8.0
Zr	170	--	--	--	--	60 - 68	--	--	[illegible]	--

TABLE 3-2. OXYGEN AND STEAM INPUT RATES FOR GASIFICATION OF VARIOUS COALS IN LURGI GASIFIERS

Coal No.	Type/Origin	Source of Data	Oxygen - kg/kg coal as charged	Steam - kg/kg coal as charged
1	Subbituminous/ Rosebud Montana	7	0.23	1.25
2	Bituminous/ Illinois No. 6	7	0.48	2.26
3	Bituminous/ Illinois No. 5	7	0.46	2.53
4	Bituminous Pittsburgh No. 8	7	0.59	3.27
5	Subbituminous/ So. African	44	--	1.74
6	Lignite/ No. Dakota	15	0.20	1.06
7	Subbituminous/ New Mexico	2	0.22	--
8	Subbituminous/ New Mexico	3	0.23	--
9	Lignite/ No. Dakota	13	0.20	--
10	Subbituminous/ Wyoming	14	0.21	--

3.2.3 Gas Purification

Rectisol solvent, methanation guard material and dehydration solvent are the input materials for the gas purification processes. Methanol is the solvent commonly used in the Rectisol process.* The purity (grade) of methanol which would be required for use in a commercial facility is not known, although it is likely that technical grade methanol would be used. Technical grade methanol has a purity of approximately 99.85% MeOH with impurities consisting primarily of water with smaller amounts of higher molecular weight alcohols, formaldehyde, acetone and/or hydrocarbons(45).

Quantities of make-up methanol (Stream 19) required would depend largely upon the specific Rectisol design. At the SASOL, South Africa Lurgi facility about 0.7 liter of make-up methanol is consumed for every 1000 Nm^3 (37,300 scf) of gas processed(44). The El Paso Burnham and WESCO designs assume 2.7 and 0.6 liters (0.6 and 0.13 gal), respectively, of make-up methanol for each 1000 Nm^3 (37,300 scf) of gas processed(2,3). In general, higher temperature regeneration will result in a greater methanol loss to the regenerator off-gas and hence a higher make-up requirement.

Zinc oxide is proposed for use as methanation guard at all commercial facilities in the U.S. No data are currently available on the quantities or composition of commercial materials which may be used in this application. Ethylene or propylene glycol are proposed for use in dehydration of methanator product. No data are available on make-up requirements for commercial facilities.

3.2.4 Gas Upgrading

Commercial cobalt molybdate-based catalysts used for shift conversion typically contain around 3% cobalt oxide and 10% molybdenum trioxide supported on alumina. The catalyst is active in the "sulfide" form and is activated during startup by exposure to raw gasifier gas containing H_2S. Make-up quantities are not known at this time. Based on experience in the petrochemical industry, shift catalyst may be regenerated by burning off the "coke" which accumulates over time. The make-up quantity depends upon the deactivation rate which is in turn a function of feed gas composition, operating conditions and the catalyst formulation.

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*Propylene in quantities of about 0.02 ℓ/1000 Nm^3 (0.0053 gal/37,300 scf) of gas processed is also proposed for use in at least one commercial design(3).

Commercial methanation catalysts are usually reduced nickel-based supported on materials such as alumina and Kieselguhr (diatomaceous earth). The properties and replacement requirements for such catalysts are generally considered proprietary and hence detailed information is not publicly available.

3.2.5 Auxiliary Processes

In a commercial Lurgi SNG facility, the Lurgi-licensed processes for pollution control/by-product recovery which require input chemicals are the Phenosolvan and the Chemie Linz AG/Lurgi processes. The Phenosolvan process can use one of several solvents depending on the specific design. In foreign gasification facilities butyl acetate and light aromatic oil have been used. Proposed commercial facilities in the U.S. are designed to use diisopropyl ether as the solvent. Make-up requirements for butyl acetate (used at the SASOL, South Africa plant) are reported at about 15 liters per million liters of gas liquor processed(44). Diisopropyl ether make-up rate for the proposed WESCO Lurgi facility is estimated at about 80 liters/10^6 liters of gas liquor(3).

No operating data are available on input chemicals to the Chemie Linz AG/ Lurgi ammonia recovery process. Proposed commercial facilities in the U.S. do not feature the use of this Lurgi-licensed process for ammonia recovery. Commonly ammonia recovery requires addition of lime or caustic to enhance stripping efficiency; alkali requirements vary with feed buffer capacity and the desired ammonia removal efficiency.

Depending on the specific processes used for raw water treatment and pollution control, a spectrum of input materials would be associated with the auxiliary processes (see Section 2.2.5). Many of these materials (e.g., lime and alum are widely used in the treatment of municipal and industrial waters and wastewaters. Input material requirements for pollution control processes which may be employed in Lurgi SNG facilities are briefly discussed in Chapter 4.

3.3 PROCESS STREAMS

Process streams in Lurgi SNG systems are defined as inputs to or outputs from gas production processes. As shown in Figure 2-2, major process streams are raw product gas (Stream 11), shifted gas (Stream 16), Rectisol product gas (Stream 24), methanator feed (Stream 26) and product SNG (Stream 32). The

TABLE 3-3. LURGI PRODUCT GAS CHARACTERISTICS AND PRODUCTION RATES

Coal No.	1	2	3	4	5	6	7	8
Type/Origin	Montana Rosebud Subbituminous	Illinois #6 High Volatile	Illinois #5 Bituminous	Pittsburgh #8 Bituminous	So. African Subbituminous	No. Dakota Lignite	New Mexico. Subbituminous	New Mexico Subbituminous
Reference	7	7	7	7	44	15	2,23	3
Gas Production Rate - Nm^3/kg (scf/lb) MAF[*]	2.0 (34)	2.3 (39)	2.3 (39)	2.4 (41)	2.3 (39)	2.1 (36)	1.95 (33)	1.95 (33)
Gas Composition (mole %) dry								
H_2	41.1	39.1	38.8	39.4	40.05	38.77	38.95	38.7
O_2	1.2	0.6	0.8	0.8	--	--	--	--
N_2 + Ar	--	0.6	0.7	0.8	--	0.12	0.31	0.3
CO_2	30.4	31.2	31.0	31.5	28.78	32.52	28.03	28.4
CO	15.1	17.3	17.5	16.9	20.20	15.63	20.20	19.9
CH_4	11.2	9.4	9.2	9.0	8.84	10.81	11.13	10.3
C_2H_4	--	--	--	--	--	0.07	0.61	0.1
C_2H_6	0.50	0.70	0.50	0.70	0.54	0.05	0.40	0.60
H_2S	0.50	1.1	1.1	0.8	--	0.35	0.37	0.50
COS	315 ppmv	180 ppmv	232 ppmv	122 ppmv	--	0.01	--	--
CS_2					--	--	0.0012	--
Mercaptans					--	--	0.01	--
Thiophenes					--	--	0.0012	--
HCN	0.0002	0.0023	0.0078	0.00066	--	--	0.0002	--
NH_3[†]	0.00012	0.0002	--	0.0002	--	0.96	--	--

[*] Moisture and ash free basis.

[†] Data for coals 1, 2, and 4 represent gas after cooling and moisture condensation; the data for coal 6 are calculated from mass balance considerations and would represent raw gas.

available data on the flow rates and characteristics of these streams and the origin and fates of environmentally important species in these streams are presented below.

3.3.1 Coal Pretreatment and Handling

Data on the characteristics of the feed coals for Lurgi SNG systems were presented in Section 3.2.1. In the Lurgi systems coal pretreatment consists of crushing and screening which would have essentially no effect on the chemical composition of the coal. Accordingly, the composition of the sized coal which is fed to the gasifier would be approximately the same as those presented in Table 3-1 for the uncrushed coal.

3.3.2 Coal Gasification

Table 3-3 presents data on Lurgi product gas compositions and production rates for four American coals tested at Westfield, Scotland (coals no. 1 through 4), three American coals which are proposed for use in commercial Lurgi SNG facilities (coals no. 6, 7 and 8), and one South African coal used at the SASOL facility (coal no. 5). Generally, Lurgi gas contains about 40% H_2, 15 to 20% CO, 28 to 32% CO_2, 9 to 11% CH_4, and around 1% C_2-C_6 hydrocarbons. For most coals the original sulfur and nitrogen in the coal are converted during gasification mainly to H_2S and NH_3, respectively, with small amounts of other reduced substances (e.g., COS, CS_2, mercaptans, thiophenes, and HCN) also produced. It should be noted that the data in Table 3-3 are for product gas after cooling; cooling of the raw gas results in bulk removal of tarry and oily substances, ammonia, and dust consisting of ash and partially gasified coal. No data are available on the composition of the gas prior to cooling.

The major variables which affect the composition at Lurgi gas are coal type, steam and oxygen feed rates, and pressure. Generally, lower rank coals yield lower quantities of gas but more total methane per unit weight of MAF (moisture and ash free basis) coal. For a given coal, methane content increases with increasing gasifier pressure up to about 2.8 MPa (450 psia). The amount of ($CO + H_2$) is dependent primarily upon coal grade but the H_2/CO ratio is influenced primarily by the steam/oxygen ratio.

Of major concern from both a product gas purification standpoint and from a pollution control standpoint are the type and amount of reduced sulfur and nitrogen species in the Lurgi product gas. Essentially no actual operating data are available for the sulfur species distribution in the product gas from the gasification of the coals to be used in the proposed commercial SNG facilities in the U.S. The proposed designs for gas purification and pollution control processes for such facilities are generally based on estimates of equilibrium sulfur species concentrations derived from thermodynamic considerations. For a number of other coals for which actual operating data are available on non-H_2S sulfur concentrations in the product gas, the actual concentrations, however, are somewhat lower than would be predicted from equilibrium considerations.*

Organic nitrogen in coal is gasified primarily to ammonia and to a lesser extent to elemental nitrogen and HCN. The data in Table 3-3 indicate that up to 80 ppmv of HCN may be present in Lurgi gas after cooling and moisture condensation. Ammonia is largely condensed with moisture and is present in cooled gas at levels of less than 10 ppmv (around 6-9 kg NH_3/tonne or 12-17 lbs NH_3/ ton MAF coal are found in Lurgi gas liquor).

3.3.3 Gas Purification

As discussed previously, after primary cooling the raw product gas from the Lurgi gasifier is split, with half sent to shift conversion and half to secondary cooling. After secondary cooling and shift conversion, the two streams are combined and sent to Rectisol treatment.

Table 3-4 presents the available data on the performance of the Rectisol process. As indicated by the data, H_2S levels of 1.0 ppmv or less in the product gas are achievable. Depending on the design, Rectisol units can remove CO_2 to a level of 10 ppm (the fourth case in the table), although for SNG production 3% CO_2 in the product gas is acceptable. Although not indicated by the data in the table, the Rectisol also removes ammonia, HCN, non-H_2S sulfur compounds and hydrocarbons heavier than ethane. Traces of methanol are to be expected in Rectisol product gas.

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*The analytical results of Westfield tests with American coals indicate non-H_2S sulfur in Lurgi product gas to range from about 120 to 300 ppmv, or about 1.5 to over 6% of the total gaseous sulfur. Based upon thermodynamic considerations the following distribution of sulfur species would be expected in Lurgi gas: H_2S, 94 to 96%; COS, 2 to 3%; CS_2, ~0.3%; mercaptans, ~2%; and thiophenes, ~0.3%(20,46). These equilibrium values indicate a non-H_2S percentage of about 4 to 6%.

TABLE 3-4. RECTISOL FEED AND PRODUCT (OUTPUT) GAS STREAM COMPOSITION*

Rectisol Type/ Source of Data	Type A† (32)		Type A‡ (41)		Type A§ (31)		Type B† (32)		Type B (32)		Type B# (22)	
Constituents/ Parameters	Input	Output	Input	Output	Input	Output	Input	Output	Input	Output	Input	Output
H_2*	58.4	74.8	40.05	57.30	43.8	63.6	62.31	94.08	61.59	94.92	63.74	93.58
CO	0.3	0.38	20.20	28.40	12.7	16.8	3.25	4.86	2.60	3.94	4.13	6.06
CH_4	0.2	0.25	8.84	11.38	10.7	14.9	0.17	0.24	0.33	0.47	0.13	0.19
CO_2	21.9	60 ppm	28.78	0.93	32.2	3.1	33.25	10 ppm	34.55	50 ppm	31.62	--
N_2 + Ar	19.2	24.57	1.59	1.77	0.29	0.43	0.53	0.82	0.41	0.67	0.12	0.17
H_2S	--	--	2480 ppmv	0.035 ppm	0.34	--	0.49	--	0.52	1 ppm	0.26	--
COS	--	--	10 ppm		--	--	10 ppm	--	--	--	63 ppm	--
CS_2	--	--	--		--	--	--	--	--	--	--	--
RSH	--	--	20 ppm		--	--	--	--	--	--	--	--
Thiophene	--	--	--		--	--	--	--	--	--	--	--
C_2^+	--	--	0.54		0.98	1.15	--	--	--	--	--	--
MeOH	--	--	--		--	--	--	--	--	--	--	--
Temp: °K (°F)	--	--	303 (86)	288 (59)	450 (351)	220 (-50)		--	--	--	303 (86)	295 (72)
Pressure: MPa (psia)	.4(356)	2.2(327)	2.5(380)	2.3(345)			3.2(480)	3.0(450)	7.1(1066)	6.9(1037)	0.3(45)	2.9(44)
Rate: Nm^3/hr (scfm)	153,100 (94,300)	118,500 (73,500)	381,000 (236,000)	263,000 (163,000)	3,032,000 (1,879,000)	2,060,000 (1,274,000)	142,340 (88,250)	94,040 (34,300)	137,000 (84,940)	88,530 (54,890)	80,000 (49,600)	54,500 (33,800)

*All values, unless otherwise noted, are in vol. %.

†Type A - Simultaneous removal of CO_2 and H_2S and simultaneous recovery of CO_2 and H_2S
Type B - Simultaneous removal of CO_2 and H_2S and separate recovery of CO_2 and H_2S

‡Data are for SASOL, S.A. Lurgi facility

§Concentrations/parameters assumed in the design of the El Paso Lurgi SNG facility

#Data are for an oil gasification plant using the Texaco gasification process.

Designs for commercial SNG facilities incorporate zinc oxide beds which would be placed between the Rectisol and methanation units to remove residual sulfur and to safeguard the catalyst should the Rectisol unit malfunction. No operating data are available on the performance of the methanation guards in Lurgi gasification service. Methanation guards, however, have been tested in connection with the Hygas coal gasification process pilot plant program. The data obtained in connection with the Hygas program are presented in Table 3-5. As noted in the table, a residual total sulfur level of about 0.05 ppmv is achieved with the use of the methanation guard. Methanation guards are expected to remove only the trace sulfur compounds and not alter the major constituent composition of the product gas stream.

3.3.4 Gas Upgrading

Gas upgrading consists of shift, methanation and drying. Although these processes have been used in many industrial applications and operating data are available for such applications, no operating data are available on performance in commercial SNG service. Table 3-6 presents data for shift conversion from bench scale tests using a simulated coal gas and the data used as the design basis for the proposed El Paso Lurgi plant.* The commercial design assumes that an H_2/CO ratio of over 9:1 is attainable at a catalyst temperature of 560°K (550°F). As indicated by the bench-scale data, the shift catalyst is active at the higher temperature of 627°K (670°F) but not at the lower temperature of 438°K (330°F). (At the higher temperature the H_2/CO ratio in the product gas approaches that which would be expected under equilibirum conditions.) Also at the higher temperature there is a reduction in the concentration of the lower molecular weight (and probably also the higher molecular weight) unsaturated organics; these organics are probably hydrogenated to saturated forms. Based on equilibrium considerations, at a temperature of about 560°K or 550°F (temperature proposed for commercial designs) about 65% of the COS and essentially all of the CS_2 would be hydrolyzed to H_2S and mercaptans, thiophenes and HCN would be almost completely hydrogenated to form H_2S and NH_3(23). Although destruction of COS, CS_2, mercaptans, thiophenes, and HCN is desirable, the downstream Rectisol unit must still be designed to handle these components, since the shift

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*The commercial designs are probably based upon test or operating data which may have been available to the process developers or designers. Such data are not published and were not available for use in this document.

TABLE 3-5. TYPICAL PERFORMANCE DATA FOR THE ZINC OXIDE SULFUR GUARD SYSTEM AT THE HYGAS PILOT PLANT(47)

Parameter/Constituent	Feed Gas	Product Gas
Temperature (°K)	617	617
Pressure (MPa)	7.64	7.56
Major Components (v%)		
Hydrogen	50.2	50
Carbon Monoxide	31.11	31
Sulfur Compounds, ppmv		
H_2S	0.53	0.003
COS	0.02	0.045
CH_3SH	0.04	0.002
CH_3SCH and CH_3CH_2SCH	0.03	0.000
(Total Sulfur)	(0.62)	(0.050)

TABLE 3-6. SHIFT CONVERSION FEED AND PRODUCT GAS CHARACTERISTICS

Parameter/Constituent	Commercial Design (31)		Bench Scale Tests (48)			
	Feed	Product	Feed	Product	Feed	Product
Reactor Temperature, °K (°F)	560 (550)	--	627 (670)	--	438 (330)	--
Reactor Pressure, MPa (psia)	2.8 (400)	--	7 (1025)	--	1.4 (200)	--
Composition						
CO	13.5	3.84	5.2	0.41	12.6	11.0
CO_2	18.6	28.2	4.1	8.3	10.5	9.5
H_2	26.1	35.85	18.6	21.9	21.7	21.1
CH_4	7.5	7.44	29.3	25.5	12.0	10.7
C_2H_6 , C_3H_8	0.4	0.4	0.80	0.78	0.22	0.19
C_2H_4, C_3H_6	0.16	0.16	0.12	0.02	0.14	0.14
COS	--	--	0.09	0	0.12	0.11
H_2S	0.24	0.24	0.60	0.6	1.18	1.32
SO_2	--	--	0.06	0.02	--	--
N_2	0.2	0.2	0.78	1.05	--	0
H_2O	32.2	22.5	40.28	41.4	32.2	45.2
Tar	.03	0.03	--	--	--	--
Oil	0.13	0.13	--	--	--	--
NH_3	0.06	0.06	--	--	--	--
H_2/CO ratio	1.9	9.33	1.7	53	1.9	1.0
H_2/CO ratio calculated at equilibrium		40		90		140

bypass gas will still contain them in the approximate levels listed in Table 3-3 for the cooled raw product gas.

Designs for proposed Lurgi SNG facilities incorporate the Lurgi fixed bed methanation process with cooling by hot gas recycle. At present, no actual operating data are available for the use of methanation on the Lurgi gas. Table 3-7 presents pilot plant data for fixed bed methanation of Hygas coal gasification process product gas and the design data for one proposed commercial facility. As confirmed by the pilot plant data, essentially all of the CO can be converted to methane when the ratio of H_2/CO is greater than three (standards for pipeline gas would generally require less than 1000 ppmv CO). Any sulfur compounds in the feed gas are also removed; these compounds are trapped by and accumulated on the catalyst. Hydrocarbons other than methane are largely reformed.

Although not indicated by data in Table 3-7, methanator product gas can contain traces of nickel carbonyl formed by the reaction of catalyst nickel with carbon monoxide. Equilibrium considerations indicate that at the temperatures which prevail near the inlet in the methanator, a $Ni(CO)_4$ concentration of several hundred ppmv can be expected(49). Although at the higher temperatures near the methanator outlet equilibrium concentration for $Ni(CO)_4$ should be less than 1 ppb, the bench scale data indicate significantly higher levels(50). The high levels of $Ni(CO)_4$ in the methanator outlet have been attributed to the very slow rate of decomposition of $Ni(CO)_4$ formed near the inlet(49).

Not all of the $Ni(CO)_4$ found in the methanator product gas can be attributed to the side reactions which may occur in the methanator. $Ni(CO)_4$ has been found in the product gas from the Lurgi gasifier at the Westfield, Scotland facility(49). This has been attributed to the reaction in the gasifier between the carbon monoxide and nickel in the coal. The cooling and dust removal and the acid gas removal apparently do not result in complete removal of any $Ni(CO)_4$ formed in the gasifier.

Dehydration of methanator product is accomplished by cooling (heat recovery) for bulk moisture condensation followed by treatment with solvents such as glycol or by molecular sieves for trace moisture removal. The estimated product gas compositions for proposed Lurgi SNG facilities are listed in Table 3-8.

TABLE 3-7. PERFORMANCE DATA FOR FIXED BED METHANATION REACTORS*

Constituent/ Parameter	Hygas Pilot Plant(51)		El Paso Burnham Design(31)	
	Feed	Product	Feed	Product
CH_4	23.6	67.4	14.9	92.7
H_2	51.6	15.5	63.5	41
CO_2	0	0	3.1	1.8
CO	12.7	0	16.9	.01
N_2 + Ar	10.4	17.1	0.4	1.1
C_2H_6, C_2H_4	1.4	0	0.45	--
H_2S	.003	<.001	--	--
COS	.045		--	--
RSH	.002		--	--
Catalyst	Harshaw Pelleted Nickel	--	Pelleted Nickel	--

*Moisture free basis

TABLE 3-8. ESTIMATED PRODUCT GAS COMPOSITIONS FOR PROPOSED LURGI SNG FACILITIES

Constituent/ Parameter	ANG(15)	El Paso(2)	WESCO(3)	Dunn County(13)
CH_4	95.95	92.92	96.84	97.57
H_2	3.00	4.15	1.45	0.97
CO	0.05	0.01	0.06	0.04
CO_2	0.40	1.81	0.50	0.40
N_2 + Ar	0.60	1.08	1.15	1.02
Heating value, kcal/Nm^3 (Btu/scf)	8630 (970)	8720 (980)	8720 (980)	8790 (988)

3.4 TOXIC SUBSTANCES IN PRODUCTS AND BY-PRODUCTS

SNG is the only product from the Lurgi SNG systems. The by-products of Lurgi SNG systems include tar, oil, naphtha, phenol, ammonia and sulfur. The by-products are produced by auxiliary processes in Lurgi systems, and the approximate quantities generated by gasification of various coals are presented in Table 3-9.

Product and by-products from Lurgi SNG facilities may contain substances which could be toxic or otherwise present hazards for occupational or general public exposure. This section reviews the composition data which have been reported for the product and various by-products of Lurgi SNG systems and identifies those substances or classes of substances which would be considered toxic. There is currently no universally accepted toxicity rating system; the EPA-developed Multimedia Environmental Goals (MEG's) hazard rating system (see Section 5.1.1) has been used in this report for the identification of potentially hazardous substances. The system,which provides one simple means of identifying through cursory inspection those pollutants most likely to pose a human health hazard, takes into account toxic and genotoxic potentials as well as cummulative or chronic effect characteristics. The MEG hazard rating system has been developed for cursory screening of potentially hazardous pollutants when detailed stream composition data are not available and mode of exposure and synergistics and antagonistic effects exerted by other substances are not defined. When certain of these additional data are available, a number of other more complex methods (e.g., comparison of composition data with MEG values - see Section 5.1.1) may be used for hazard assessment.

3.4.1 Coal Pretreatment and Handling

No by-products are generated in this operation.

3.4.2 Coal Gasification

Although tars, oils, phenols, etc. are produced as by-products in the Lurgi gasifier, such by-products are recovered in subsequent processes for gas purification and pollution control (see Sections 3.4.3 and 3.4.5).

3.4.3 Gas Purification

A naphtha by-product is generated during acid gas removal from cooled product gas. The principal constituents of the naphtha are butenes (C_4 olefins), benzene, toluene, xylene and smaller quantities of higher molecular weight

TABLE 3-9. LURGI BY-PRODUCT PRODUCTION QUANTITIES (KG/KG MAF* COAL)

Coal No.[†]	1	2	3	4	5	6	7	8	9	10
Data Source	7	7	7	7	44	15	2	3	13	14
Tar	30	30	39	41	15	56	74	49	75	53
Oil	30	5	7	9	7	9	41	50	13	
Naphtha	--	--	--	--	4	11	17	21	10	
Phenol	7	6	6	4	4	7	9	7	11	8
Ammonia	6	8	8	8	8	14	89	13	8	7
Sulfur	--	--	--	--	--	--	13	8	14	4

*MAF = moisture and ash free basis

[†] Coal numbers refer to coal listed in Table 3-1

aromatics. Under the MEG "cursory" hazard rating system, benzene is rated "hazhardous" whereas both xylene and toluene are rated as "nonhazardous;" no MEG rating has yet been established for butenes.

3.4.4 Gas Upgrading

Table 3-8 presents the estimated composition for the product gas from Lurgi SNG systems. As indicated by the data in the table, the primary constituent of SNG is methane with smaller quantities of H_2, CO, CO_2, N_2 and Ar also present. The MEG "cursory" hazard rating system rates CH_4, CO_2 and CO as "nonhazardous." It should, however, be noted that CO is classified as a "criteria" air pollutant and is considered an occupational hazard. Although no MEG ratings are yet available for N_2, H_2 and Ar, these gases are not considered toxic (N_2 and Ar are components of the atmosphere). As noted in Section 3.3.4, trace quantities of $Ni(CO)_4$ may also be present in the Lurgi SNG. The MEG system rates $Ni(CO)_4$ as "very hazardous." This substance is a well known carcinogen.

3.4.5 Auxiliary Processes

Tars, oils, phenol, ammonia and sulfur are the by-products recovered in water or air pollution control processes. No actual composition data are available for the organics in the Lurgi tars. However, some composition data are available for the tars produced in the Synthane coal gasification process. These data which are presented in Table 3-10 are indicative of the type of substances which would be expected in the Lurgi tars. Under the MEG hazard rating system, some of the substances/class of substances in the Synthane tar (e.g., pentacyclic aromatics and N-heterocyclics) would be rated as "hazardous," "very hazardous" or "most hazardous."

Table 3-11 presents data on minor and trace elements in the Lurgi tar and oil. As noted in the table, some of the elements which are present in relatively higher concentrations (e.g., arsenic, mercury and nickel) would be rated as "most hazardous." A number of trace elements which are found in smaller amounts (e.g., vanadium, barium, cobalt, boron and copper) would be rated as "very hazardous," "hazardous" or "nonhazardous."

Very limited data are available on the organic substances in the Lurgi oil. Some of the substances which have been identified in the oil from the Westfield Lurgi plant are shown in Table 3-12. As indicated by the data, crude Lurgi oil contains about 90% aromatic compounds and about 1.8% thiophenes. With the

TABLE 3-10. COMPOSITION OF BENZENE SOLUBLE TARS PRODUCED IN SYNTHANE GASIFICATION PROCESS (52,53)

Compound/Class	Type/Origin of Coal				MEG Hazard Rating*
	Bituminous (Illinois)	Lignite (N. Dakota)	Subbituminous (Montana)	Bituminous (Pennsylvania)	
	Volume %				
Mono Aromatics					
Benzene	2.1	4.1	3.9	1.9	X
Phenols	2.8	13.7	5.5	3.0	NH
Di Aromatics					
Naphthalenes	11.6	19.0	15.3	16.5	NH
Indans/Indenes	10.5	5.0	7.5	8.2	NH
Naphthols and Indanols	0.9	11.4	11.1	2.7	--
Tri Aromatics					
Phenylnaphthalenes	9.8	3.5	6.4	7.6	NH
Acenaphthenes	13.5	12.0	11.1	15.8	--
Fluorenes	9.6	7.2	9.7	10.7	NH
Anthracenes/ Phenanthrenes	13.8	10.5	9.0	14.8	NH
Acenaphthols	--	2.5	4.9	2.0	--
Phenanthrols	2.7	--	0.9	--	--
Tetracyclic Aromatics					
Pericondensed (benzanthracenes, chrysene)	7.2	3.5	4.9	7.6	NH to XX
Catacondensed (pyrene, benzphenanthrenes)	3.0	1.4	3.0	4.1	NH to XX
Pentacyclic Aromatics	trace			trace	NH to XXX
Heterocyclics					
Dibenzofurans	6.3	5.2	5.6	4.7	--
Dibenzothiophenes and Benznaphthothiophenes	6.2	1.0	1.5	2.4	--
N-Heterocyclics	10.8	3.8	5.3	8.8	NH to XX

*MEG hazard rating: X = hazardous, XX - very hazardous, XXX - most hazardous, NH - nonhazardous and -- = not rated.

TABLE 3-11. COMPOSITION OF TARS AND OILS PRODUCED BY GASIFICATION OF VARIOUS COALS IN LURGI GASIFIERS

Coal Number	1		2		3		4		5		6		9		
Coal Type/Origin (Reference)	Subbituminous Montana Rosebud (7)		Bituminous Illinois #6 (7)		Bituminous Illinois #5 (7)		Bituminous Pittsburgh #8 (7)		Bituminous S. African (44)		Lignite N. Dakota (15)		Lignite N. Dakota (13)		MEG Hazard Rating* (53)
	Tar	Oil	Tar	Oil	Tar	Oil	Tar	Oil	Tar	Oil	Tar	Oil	Tar	Oil	
Production Rate, kg/tonne coal (dry basis)	26	26	27	5	35	6	38	8	15	8	15	8	15	6	
Elemental Composition (wt %)															
C	83.1	81.3	85.5	84.8	85.9	84.9	88.5	87.3	--	--	--	--	--	--	
H	7.7	9.2	6.4	7.8	6.4	7.7	5.9	7.6	--	--	--	--	--	--	
N	0.65	0.5	1.2	0.7	1.2	0.5	0.9	0.5	--	--	--	--	--	--	
S	0.28	0.5	1.7	2.4	2.4	2.3	1.5	1.5	0.3	0.25	0.65	0.52	--	--	
O	8.2	8.5	5.2	4.3	4.2	4.7	3.2	3.2	--	--	--	--	--	--	
Ash	0.05	0.03	0.03	0.01	0.01	0.01	0.01	0.01	--	--	0.45	--	--	--	
Phenols	5.3	19.1	2	20.1	4.7	19.2	1	10	--	--	--	--	--	--	
Minor and Trace Elements (ppmv)															
Ag	--	--	--	--	--	--	--	--	--	--	--	--	<0.2	<1	X
As	--	--	--	--	--	--	--	--	4	26	7	24	2	1.7	XXX
B	--	--	--	--	--	--	--	--	50	0.5	1	4	20	30	NH
Ba	--	--	--	--	--	--	--	--	--	--	2	560	15	0.5	X
Be	--	--	--	--	--	--	--	--	0.8	0.05	--	<0.1	0.1	0.05	XXX
Br	--	--	--	--	--	--	--	--	<.04	<.04	<0.1	<0.2	--	--	NH
Cd	--	--	--	--	--	--	--	--	<.05	<0.3	<0.3	<0.5	<0.1	<0.1	XXX
Ce	--	--	--	--	--	--	--	--	4	<0.3	4	--	--	--	--
Co	--	--	--	--	--	--	--	--	--	--	0.6	0.9	0.05	0.02	XX
Cr	--	--	--	--	--	--	--	--	--	--	5	4	1	0.6	XXX
Cs	--	--	--	--	--	--	--	--	--	--	0.2	--	--	--	--
Cu	--	--	--	--	--	--	--	--	--	--	3	2	0.1	2	XX
F	--	--	--	--	--	--	--	--	4	<0.5	51	5	12	.06	--
Ga	--	--	--	--	--	--	--	--	--	--	0.6	--	--	--	X
Ge	--	--	--	--	--	--	--	--	--	--	0.1	--	--	--	X
Hg	--	--	--	--	--	--	--	--	0.4	<0.1	2.9	0.16	<0.1	<0.1	XXX
Li	--	--	--	--	--	--	--	--	--	--	0.7	0.1	0.5	0.5	X
Mo	--	--	--	--	--	--	--	--	--	--	2	6	0.02	0.02	NH
Mn	--	--	--	--	--	--	--	--	2.5	0.3	11	0.7	--	--	X
Ni	--	--	--	--	--	--	--	--	2.5	1.2	3	2	10	1.5	XXX
P	--	--	--	--	--	--	--	--	--	--	90	2	--	--	--
Pb	--	--	--	--	--	--	--	--	50	1	14	4	1.5	0.15	XX
Rb	--	--	--	--	--	--	--	--	--	--	2	0.2	--	--	--
Sb	--	--	--	--	--	--	--	--	0.8	0.5	--	--	<0.05	<0.02	XXX
Sc	--	--	--	--	--	--	--	--	--	--	0.7	2	--	--	--
Se	--	--	--	--	--	--	--	--	--	--	0.2	0.4	0.2	<0.01	XXX
Sn	--	--	--	--	--	--	--	--	--	--	--	--	0.2	<0.05	--
Sr	--	--	--	--	--	--	--	--		--	84	0.3	--	--	NH
Te	--	--	--	--	--	--	--	--	--	--	--	--	--	--	X
U	--	--	--	--	--	--	--	--	--	--	0.9	--	5	<1	XX
V	--	--	--	--	--	--	--	--	5	0.2	3	0.2	0.05	0.15	X
W	--	--	--	--	--	--	--	--	--	--	--	--	--	--	NH
Y	--	--	--	--	--	--	--	--	--	--	3	1	--	--	NH
Zn	--	--	--	--	--	--	--	--	--	--	0.9	2	6	0.4	NH
Zr	--	--	--	--	--	--	--	--	--	--	10	1	--	--	--
Al	--	--	--	--	--	--	--	--	--	--	1500	150	--	--	NH
Ca	--	--	--	--	--	--	--	--	--	--	2600	230	--	--	NH
Fe	--	--	--	--	--	--	--	--	--	--	1500	100	--	--	NH
K	--	--	--	--	--	--	--	--	--	--	178	35	--	--	NH
Na	--	--	--	--	--	--	--	--	--	--	700	390	--	--	NH
Si	--	--	--	--	--	--	--	--	--	--	4200	180	--	--	NH
Ti	--	--	--	--	--	--	--	--	--	--	92	5	--	--	NH
Mg	--	--	--	--	--	--	--	--	--	--	764	19	--	--	NH

*MEG hazard rating: X = hazardous, XX = very hazardous, XXX = most hazardous, NH = nonhazardous, -- = not rated.

TABLE 3-12. ORGANIC COMPOSITION OF LURGI OIL PRODUCED AT THE WESTFIELD LURGI FACILITY(54)

Compound/Class	Concentration (wt %)
Paraffins	10.71
Olefins	--
Aromatics	89.3
Sulfur (total)	--
Benzene	19.56
Toluene	28.40
Xylene and ethyl benzene	14.7
Ethyl toluene	2.69
Trimethyl benzenes	11.8
Styrene	1.07
Indane	1.43
1,2-benzofuran	1.09
Indene	5.37
Naphthalene	1.40
Thiophenes	1.77
	100

exception of benzene which is rated as "hazardous" and styrene which is not yet rated, all substances or classes of substances listed in Table 3-12 are rated as "nonhazardous" under the MEG system.

No data are published on the composition of the crude phenols recovered by the Phenosolvan process for the treatment of the Lurgi gas liquor. However, some data are available on the types of phenolic compounds present in the gas liquor (see Table 3-13). These data indicate that monohydric phenols account for 50% to 80% of the total phenolic materials in the gas liquor. As noted in Table 3-13, other classes of phenols found in the gas liquor are catechols and resorcinols. Although a MEG rating has not yet been developed for all individual members of these classes of phenols, those which have been rated are rated as "nonhazardous." Since the Phenosolvan solvent would be expected to extract organics other than phenols which are present in the gas liquor, the by-product crude phenol is expected to contain some of such organics. One such organic compound which would most likely be present in the crude phenol is benzene which is rated as "hazardous."

TABLE 3-13. PHENOL COMPOSITION BREAKDOWN FOR RAW LURGI GAS LIQUOR(44) (VALUES IN MG/l)

Phenol Class/Compound	Tar Separator	Oil Separator
Total phenols	3570	5100
Monohydric phenols	1843	4560
Phenol	1260	3100
Cresols	483	1027
Xylenols	100	393
Catechols	1379	380
Resorcinols	348	240

Ammonia is recovered as by-product in the treatment of gas liquor by steam stripping. The ammonia recovered as the by-product in the Lurgi system may be contaminated with other hazardous substances. No actual data are available on the impurities present in the by-product ammonia.

Elemental sulfur would be a by-product recovered in the treatment of concentrated acid gases for air pollution control. Although sulfur itself is rated as nonhazardous, it may be contaminated with hazardous impurities. When the Stretford process is employed, the by-product sulfur has been determined to contain traces of vanadium and other solvent-derived salts. Vanadium is rated as "hazardous" under the MEG rating system.

3.5 WASTE STREAMS TO AIR

Figure 3-1 shows the process modules in Lurgi systems for SNG production which generates gaseous wastes. The 12 major types of gaseous wastes identified are (1), crushing/screening off-gas (Stream 2), (2) lockhopper vent gas (Streams 6 and 8), (3) ash quench off-gas (Stream 78), (4) concentrated acid gases (Streams 21, 22 and 23), (6) catalyst decommissioning/regeneration off-gases (Stream 27), (6) depressurization and stripping gases (Streams 81 and 69), (7) by-product sotrage vent gases (Stream 101), (8) oxygen plant vent gas (Stream 66), (10) transient waste gases (Stream 102), (11) flue gases from steam and power generation (Stream 64) and (12) fugitive emissions (not indicated in Figure 3-1). Available data for these waste streams are presented and discussed in this section. The pollution control processes for the management of the waste streams are discussed in Chapter 4.

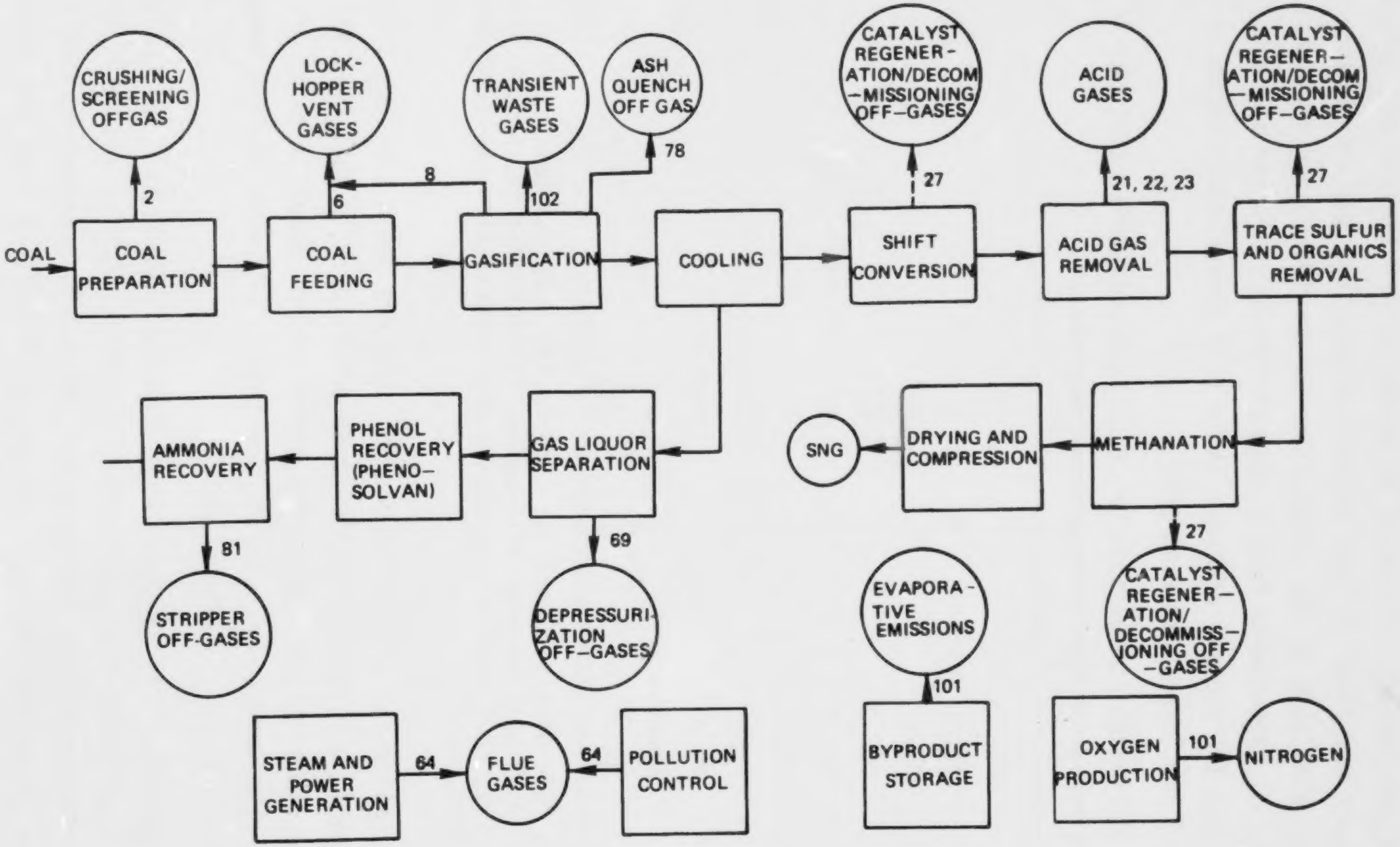
3.5.1 Coal Pretreatment and Handling

As discussed in Section 2.2, Lurgi gasifiers require only crushing and screening to obtain a suitably sized coal feed. Uncontrolled fugitive dust emissions associated with crushing, screening, conveying and storage/reclamation are estimated at 0.038 to 0.045 kg/1000 kg coal processed(3). Emissions data from actual operations are not available at present. It might be noted that potential emissions from coal preparation for Lurgi gasification are likely to be lower than those from coal preparation for gasification processes which require pulverized coal.

3.5.2 Coal Gasification

Emission streams directly associated with the gasifier are the lockhopper vent gases and gases generated during transient operation (startup and upset conditions).

Feed Lockhopper Vent Gas. As discussed in Section 2.2.3, most of the proposed designs for commercial Lurgi SNG facilities in the U.S. feature the use of


CRUSHING/ SCREENING OFFGAS
LOCK-HOPPER VENT GASES
TRANSIENT WASTE GASES
ASH QUENCH OFF GAS
CATALYST REGENER-ATION/DECOM-MISSIONING OFF-GASES
ACID GASES
CATALYST REGENER-ATION/DECOM-MISSIONING OFF-GASES
2
6
8
102
78
27
21, 22, 23
27
COAL
COAL PREPARATION
COAL FEEDING
GASIFICATION
COOLING
SHIFT CONVERSION
ACID GAS REMOVAL
TRACE SULFUR AND ORGANICS REMOVAL
AMMONIA RECOVERY
PHENOL RECOVERY (PHENO-SOLVAN)
GAS LIQUOR SEPARATION
SNG
DRYING AND COMPRESSION
METHANATION
81
69
27
STRIPPER OFF-GASES
DEPRESSURI-ZATION OFF-GASES
EVAPORA-TIVE EMISSIONS
CATALYST REGENER-ATION/ DECOMMISS-IONING OFF-GASES
101
STEAM AND POWER GENERATION
64
FLUE GASES
64
POLLUTION CONTROL
BYPRODUCT STORAGE
OXYGEN PRODUCTION
101
NITROGEN

LEGEND:

21,22,23	Combined Gases from Rectisol Unit
2	Fugitive Coal Dust
6	Coal Lockhopper Vent Gas
8	Ash Lockhopper Vent Gas
102	Transient Waste Gases
78	Ash Quench Off-gas
27	Catalyst Decommissioning Off-gas
81	Stripper off-gas
69	Depressurization Gas
66	Nitrogen
64	Utility Boiler Flue Gas
101	By-product Storage Vent Gases
27	Catalyst Decommissioning Off-gas

Figure 3-1. Process Modules Generating Gaseous Wastes in Lurgi SNG Systems

product gas for feed lockhopper pressurization. About 3% to 4% of the product gas is used for this purpose. Most of the gas used for pressurization is returned to the product gas stream; only about 3% of the pressurization gas (about 0.1% of the total product gas flow) is lost as the off-gas from the lockhopper. No operating data are available on the composition of the lockhopper vent gas. This gas, however, is expected to have a composition very similar to that of the product gas used for pressurization. Table 3-14 presents one estimate for the composition of the lockhopper vent gas.

TABLE 3-14. ESTIMATED COMPOSITION OF LURGI FEED LOCKHOPPER VENT GAS*(31)

Component	Vol %
CO_2	28
Total sulfur	0.3
C_2H_4	0.4
CO	20
H_2	39
CH_4	11
C_2H_6	0.6
N_2	0.4
Naphtha	0.1
H_2O	1.0

*Based on the following assumptions: New Mexico subbituminous coal with 0.7% sulfur; coal bulk density 1016 kg/Nm^3 (60 lb/scf); lockhopper filled to 90% capacity; coal void volume 30%; and pressurization gas compressed to 3.1 MPa (445 psia).

One commercial design (the WESCO design) features the use of CO_2 (from the Rectisol process) for feed lockhopper pressurization. In this case the lockhopper vent gas would be significantly larger in volume (about 3% to 4% of the product gas flow rate) and would consist of primarily CO_2 with smaller amounts of the constituents in the raw product gas.

Ash Lockhopper Vent Gas and Ash Quench Off-gas. Steam is utilized for pressurization of ash lockhoppers to prevent air from entering the gasifier or product gas from flowing out of the gasifier. As ash is transferred from the lockhopper to the ash quench chamber, vent gases are emitted from the lockhopper containing ash particles and components of the gasifier gas. The ash discharged from the lockhopper is quenched with water. The quenching of the ash results in the emission of an off-gas which contains mostly steam and particulate matter. If process water is used to quench the ash, the resulting off-gas would be expected to contain trace amounts of volatile substances originally present in the wastewater. No data are available on the composition or the volumes of the ash lockhopper vent gas and the ash quench off-gas. The domestic coals likely to be used in Lurgi SNG plants have ash contents ranging from 5.6 to 25.6% (see Table 3-1). Hence, the mass (and consequently the volumetric) flow rate through the ash lockhopper would be much smaller than that through the feed lockhopper. Accordingly, the size of the ash lockhopper and hence the volume of the ash lockhopper vent gas would be significantly smaller than the size of the feed lockhopper and the volume of the feed lockhopper vent gas, respectively.

Transient Waste Gases. Raw gas produced during startup and upset conditions is not generally of a quality suitable for SNG production. These gases are produced only intermittently and would generally be discharged to the atmosphere through a flare. Data concerning the composition of the transient gases are not currently available. The lower temperature conditions during startup may result in an increased production of volatile organic compounds in the gasifier. Some of these compounds may be condensed in the gas cooling step; those not condensed will probably be destroyed in the flare. Actual destruction efficiency of these compounds in a flare is not known.

3.5.3 Gas Purification

Concentrated acid gases produced in the Rectisol process are the only waste gases associated with the gas purification operation. Table 3-15 presents reported composition data for concentrated acid gases from several Rectisol systems operated in selective (separate H_2S and CO_2 removal) and non-selective (combined H_2S and CO_2 removal) modes, and one set of data used is the design for the proposed El Paso Burnham coal gasification facility (third set of data in Table 3-15). The second set of data in Table 3-15 is for the non-selective Rectisol process at the SASOL, South Africa coal gasification plant and represents acid compositions expected from facilities handling low to medium sulfur coals. The last set of data, which is for a selective Rectisol process handling a product gas from an oil gasification facility, provides an indication of the degree of selectivity which can be achieved by the application of the selective Rectisol process.

TABLE 3-15. CHARACTERISTICS OF ACID GASES PRODUCED BY THE RECTISOL PROCESS

Constituents/ Parameters	1		2			3			4			5			6		
	Type A*(32)		Type A‡(44)			Type A§(31)			Type B*(32)			Type B(32)			Type B#(22)		
	22		21	22	23	21	22	23	21	22	23	21	22	23	21	22	23
H_2	0.4	--	21.4	2.6	0.14	29.6	0.4	--	0.15	0.79	--	0.76	--	--	0.33	--	--
CO	0.014	--	18.2	4.8	0.0	11.9	0.2	--	0.05	0.22	--	0.11	--	--	0.14	--	--
CH_4	0.017	--	11.4	7.2	0.9	31.0	0.6	--	--	0.05	--	0.06	--	--	0.00	--	--
CO_2	73.95	--	46.7	83.4	97.2	28.5	97.5	78.8	76.81	98.91	64.6	09.85	--	68.31	80.19	--	68.46
N_2 + Ar	25.62*	--	1.5	0.8	0.03	0.2	--	--	23.0†	0.05	0.1	8.22*	--	1.92	19.34*	--	--
H_2S	--	--	3176 ppm	4941 ppm	8824 ppm	--	0.8	12.6	2 ppm	2 ppm	35.2	5 ppm	--	29.77	<5 ppm	--	30.78
COS	--	--	--	--	0.003	--	--	--	--	--	0.1	--	--	--	8 ppm	--	0.76
C_2+	--	--	0.7	1.1	0.7	2.2	0.5	--	--	--	--	--	--	--	--	--	--
MeOH	--	--	--	--	--	--	--	8.6	--	--	--	--	--	--	--	--	--
CS_2	--	--	--	--	0.0002	--	--	--	--	--	--	--	--	--	--	--	--
RSH	--	--	--	--	0.028	--	--	--	--	--	--	--	--	--	--	--	--
Thiophene	--	--	--	--	0.0002	--	--	--	--	--	--	--	--	--	--	--	--
Temp: °K(°F)	--	--	273(32)	273(32)	268(23)	220(-50)	220(-50)	300(80)	--	--	--	--	--	--	295(72)	--	322(121)
Pressure: MPa (psia)	0.1(15)	--	1.3(195)	0.46(70)	0.1(15)	0.7(103)	.2(25)	0.1(15)	0.1(15)	0.24(36	0.24(36)	0.1(16)	--	0.2(28)	0.1(15)	--	0.5(73)
Rate: Nm^3/hr (scf/min)	45,090 (27,956)	--	4,500 (2,852)	15,000 (9,300)	98,000 (60,760)	14,100 (8,780)	355,000 (220,850)	9,720 (6,050)	41,480 (25,845)	14,130 (8,760)	1,980 (1,230)	50,280 (21,170)	--	2,390 (1,480)	30.800 (19,100)	--	673 (417)

*Type A - simultaneous removal of CO_2 and H_2S with simultaneous recovery of CO_2 and H_2S
Type B - simultaneous removal of CO_2 and H_2S with separate recovery of CO_2 and H_2S

†Includes H_2 stripper at 350,000 Nm^3/hr (223,000 scf/min)

‡Data are for SASOL, So. Africa Lurgi plant

§Concentrations/parameters assumed in the design of the El Paso Lurgi SNG facility

#Data are for an oil gasification plant using the Texaco gasification process

Very little data are available on trace constituents which may be present in Rectisol acid gases. Based on the data in Table 3-15, COS tends to concentrate in the H_2S-rich acid gas stream (Stream 23). Some trace constituents such as HCN, naphtha hydrocarbons and mercaptans are originally present in the feed gas to the Rectisol process(55). Methanol from the prewash column is regenerated in the azeotrope column where the hydrocarbons and HCN are separated. The HCN is reabsorbed in water and recycled to the shift conversion process where it reacts to form ammonia and CO. The bulk of the mercaptans remain with the hydrocarbons (naphtha) which are subsequently recovered as a by-product.

3.5.4 Gas Upgrading

The only waste gas streams associated with the gas upgrading operation are the off-gas from the regeneration/decommissioning of catalyst. Both shift and methanation catalysts require periodic regeneration or replacement due to deactivation by sulfur compounds and carbon deposition. In the case of shift catalyst, the carbon residue would be burned off resulting in an off-gas containing sulfur compounds, catalyst-derived particulate matter, CO_2 and CO. The spent methanation catalyst which contains reduced nickel is pyrophoric, thus requiring controlled oxidation of the nickel before the spent material is removed from the bed. Oxidation results in a sulfur rich off-gas containing catalyst particulates, $Ni(CO)_4$, and oxidation products such as CO, CO_2, etc. Because of the proprietary nature of catalysts and their handling procedures, no data have been published on the characteristics of such regeneration/decommissioning off-gases and on regeneration procedures. The emissions associated with catalyst decommissioning and regeneration (or reclamation) are expected to be small in volume and of infrequent nature.

3.5.5 Auxiliary Processes

Few gaseous waste streams from auxiliary processes can be considered unique to Lurgi SNG systems (e.g., the off-gas from the depressurization of the Lurgi gas liquor). Most of the other waste streams, however, are of the type which are encountered in other industries. This section presents the available data on waste gases from the auxiliary processes; where sufficient data are unavailable, a qualitative discussion of some of the expected characteristics of the waste streams is presented.

Depressurizing and Stripping Off-Gases. Raw product gas from the gasifier is quenched and cooled to remove condensible hydrocarbons and unreacted steam prior to gas purification. Quenching produces a pressurized aqueous and organic condensate stream. When this stream (Lurgi gas liquor) is subsequently depressurized for the separation and recovery of tars and oils for wastewater treatment, an off-gas is generated which contains some of the volatile components and gases originally contained in the liquid phase(s). The major components of such off-gases are carbon dioxide, carbon monoxide, hydrogen sulfide, ammonia, hydrogen and low molecular weight organics (e.g., methane). Table 3-16 contains data on the composition of depressurization gases associated with tar and oil separation from Lurgi quench condensates. The data indicate that these off-gases contain significant quantities of H_2S and NH_3. No information is available on the minor constituents (e.g., COS and HCN) which may be present in these off-gases.

In the treatment of Lurgi gas liquor for the recovery of hydrogen sulfide and ammonia by distillation or gas stripping, an off-gas is generated which contains these and other volatile and gaseous compounds (e.g., HCN, CO, CO_2, CH_4, and COS). Depending upon the feed composition and the stripper design, relatively concentrated H_2S and NH_3 streams can be obtained. Steam stripping can generally result in the removal of greater than 99% of the H_2S and 95% of the ammonia in the sour water feed. No operating data are available on the actual composition of the stripper off-gas in applications to gas liquor from the Lurgi process. Designs for sour water stripping/ammonia recovery and the expected stripper overhead compositions are discussed in Section 4.3.

By-product Storage Vent Gases. The Lurgi process generates naphtha and tars and/or oils during gasification; these are recovered as by-products for sale or used as fuel within the facility. Evaporative emissions may be associated with storage of these by-products. These emissions are usually in the form of vent gases from storage facilities and generally contain the same constituents as are present in the stored material. The concentrations of these constituents in the gas phase are a function of the concentrations in the liquid phase, the volatility of substances and the temperature. Estimates of evaporative emissions for the proposed El Paso Lurgi SNG facility are shown in Table 3-17. For comparison purposes, material production/use rates for these substances are also presented.

TABLE 3-16. COMPOSITION OF LURGI TAR/OIL SEPARATOR DEPRESSURIZATION GAS

Coal Used Reference	Montana Rosebud (7)		Illinois #6 (7)		Illinois #5 (7)		Pittsburgh #8 (7)		New Mexico Subbituminous (31)
Constituent*	Tar Sep.	Oil Sep.	Tar Sep.	Oil Sep.	Tar Sep.	Oil Sep.	Tar Sep.	Oil Sep.	Combined Flash Gases
H_2S	3.8	8.6	5.7	5.5	6.2	6.8	4.4	5.5	0.3
NH_3	6.3	12.0	1.0	1.8	4.6	2.7	2.9	3.5	--
CO_2	64.7	59.3	84.9	85.5	62.9	67.0	71.3	73.9	32.1
CO	5.9	4.7	1.5	0.8	4.5	4.2	4.7	3.8	11.6
H_2	2.9	2.3	3.5	3.6	11.7	13.3	12.0	0.6	43.7
O_2 + Argon	3.1	2.5	0.4	0.6	1.3	1.4	0.3	0.2	0.3
N_2	8.0	6.4	1.2	1.0	5.9	2.3	1.0	0.8	
CH_4	5.3	4.2	1.8	1.2	2.9	2.3	3.4	2.7	10.7

*All data are vol %

TABLE 3-17. ESTIMATED BY-PRODUCT STORAGE EMISSION RATES FOR THE PROPOSED EL PASO LURGI SNG PLANT(21)

Product/ By-Product	Total Production/Use Rate kg/hr	(lb/hr)	Emission Rates kg/hr	(lb/hr)
Crude phenol	5,118	(11,260)	0.68	(1.5)
Tar oil	22,090	(48,600)	1.18	(2.6)
Naphtha	9,090	(20,000)	0.95	(2.1)
Ammonia	9,727	(21,400)	0.68	(1.5)
Product gases	233,600	(514,000)	1.45	(3.2)
Methanol	1,218	(2,680)	0.73	(1.6)
Tar	40,360	(88,800)	--	--

Oxygen Plant Vent Gases. An on-site oxygen plant is needed to satisfy the oxygen requirement. No chemical reactions are involved in the cryogenic air separation process. The emissions stream from the oxygen plant is the separated nitrogen (containing trace atmospheric gases) which is the main component of the air feed to the plant. Approximately 0.2 kg of oxygen is required per kilogram of coal used in the gasifiers. For a commercial sized plant (around 7 x 10^6 Nm^3/d or 250 x 10^6 scf/d of SNG), this results in a nitrogen vent stream of approximately 7 x 10^5 kg/hr (1.6 x 10^6 lb/hr).

Steam and Power Production Flue Gases. A major gaseous waste stream in an integrated Lurgi SNG facility is the flue gas resulting from combustion of fuels to generate power and/or steam onsite. The composition and quantity of such flue gases depend upon the fuel used, whether electricity is generated onsite and on the manner in which the fuel is combusted (e.g., gas turbine vs. boiler). Generally, three types of fuel may be used for onsite steam and power generation: (1) coal, particularly fines generated by crushing/screening; (2) by-products (tar, oil, phenols, naphtha); and (3) fuel gas produced by onsite low Btu gasification. Product SNG would not ordinarily be an economical fuel alternative. The use of all of the above three fuels has been proposed for one or more of the proposed commercial Lurgi SNG facilities.

The proposed design for the El Paso coal gasification facility in New Mexico incorporates the use of low Btu Lurgi gasifiers for fuel gas production. The raw product gas is cooled and desulfurized in a high pressure Stretford unit prior to utilization as fuel(2). The low Btu gas will be used in boilers for steam production and in gas turbines to drive generators and oxygen plant compressors. The gas turbines would exhaust to waste heat boilers which would produce steam for motive power, process uses and process heating.

The proposed Wyoming Coal Gasification Project includes onsite steam and power production facilites(14). A combination of process waste heat boilers and boilers fired with coal fines will be used for steam production. Electrical power will be generated utilizing a series of steam-driven turbine generators. The coal-fired boilers will operate on low sulfur medium ash coal and will be equipped with hot side high efficiency electrostatic precipitators.

Electrical power for the WESCO Project will be supplied by a local electric utility(3). High pressure steam will be generated onsite in boilers fired with coal fines. Particulates will be removed with hot side electrostatic precipitators. An FGD system will be used to remove 90% of the SO_2. Boilers are designed to minimize NO_x emissions.

The proposed ANG Coal Gasification Project will purchase electrical power from an off-site utility(15). Plant steam requirements will be supplied from two sources: boilers fired by liquid by-products and waste heat boilers.

When coal or gasification by-products are utilized, the uncontrolled emissions will contain the bulk of the original fuel sulfur, NO_x (derived from the nitrogen in the fuel and in the combustion air), and, in the case of coal, a high concentration of particulates. When fuel gas is produced onsite, sulfur and nitrogen compounds and particulates are generally removed from combustion. The flue gases from use of fuel gas, therefore, will generally be lower in total sulfur, particulates, and NO_x than flue gases from direct combustion of coal, tars and oils. It should be noted that onsite fuel combustion is not a source of emissions unique to Lurgi SNG production, but is common to many types of industries. The use of fuels such as low Btu gas and coal-dervied tars and/oils, however, would be unique to Lurgi facilities. At present no operating data are available on the composition of controlled or uncontrolled flue gases from the combustion of these "unconventional" fuels.

Fugitive Emissions. A variety of sources may generate fugitive emissions in an integrated SNG facility. These include compressors, pumps, valves, flanges, pressure relief valves, wastewater treatment plants and loading and transportation equipment and vessels. The actual compositions of the fugitive emissions vary widely, primarily depending on the specific emission source and the nature of the product handled. The major components of concern in many of these fugitive emissions are hydrocarbons and particulates. At present there are no data available relating to the magnitude or characteristics of fugitive emissions associated with Lurgi systems.

3.6 WASTE STREAMS TO WATER

Figure 3-2 shows the process modules in a Lurgi SNG system generating aqueous wastes. The gasification waste streams identified are: (1) coal pile runoff (Stream 100), (2) ash quench slurry (Stream 79), (3) raw gas liquor (Stream 13), (4) Rectisol methanol/water still bottoms (Stream 18), and (5) methanation/dehydration condensate (Streams 29 and 31). Phenosolvan filter backwash (Stream 76) and clean gas liquor (Stream 82) are aqueous wastes associated with Lurgi processes for phenol/ammonia recovery (and wastewater treatment). Aqueous wastes associated with non-pollution control auxiliary processes include: boiler blowdown (Stream 86), cooling tower blowdown (Stream 95) and raw water treatment brines and filter backwash wastes (Streams 41 and 49). The available data on aqueous wastes from gasification, ammonia/phenol recovery and non-pollution control processes are presented below. Aqueous wastes from pollution control processes are discussed in Chapter 4.0.

3.6.1 Coal Pretreatment and Handling

The major aqueous waste stream associated with this operation is the runoff from coal piles. The volume and characteristics of the wastewater depend on the type and size of coal stored, the design of the storage facility and climatic conditions. In general, the coal pile runoff is expected to contain coal fines and other suspended particulate matter, and dissolved inorganics resulting from oxidation and solubilization of coal impurities. Although some data are available on the characteristics of coal pile runoff from coal storage facilities in other industries, because of the site- and coal-specific nature of runoff, such data may not necessarily represent the characteristics of runoff from coal piles at a Lurgi SNG plant. At present no data are available for the anticipated coal pile runoff from proposed commercial Lurgi SNG plants.

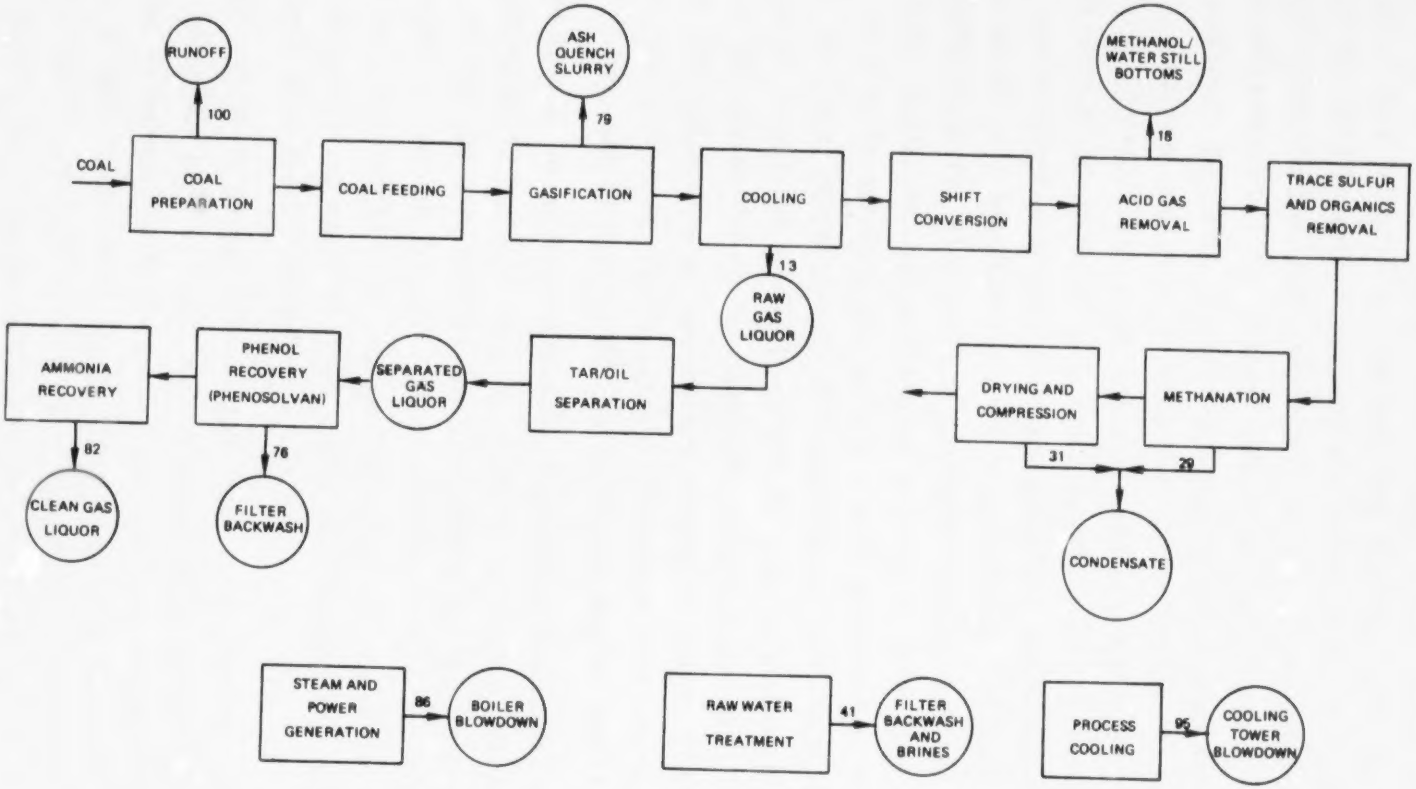

COAL
COAL PREPARATION
100
RUNOFF
COAL FEEDING
GASIFICATION
79
ASH QUENCH SLURRY
COOLING
13
RAW GAS LIQUOR
SHIFT CONVERSION
ACID GAS REMOVAL
18
METHANOL/ WATER STILL BOTTOMS
TRACE SULFUR AND ORGANICS REMOVAL
METHANATION
DRYING AND COMPRESSION
31
29
CONDENSATE
TAR/OIL SEPARATION
SEPARATED GAS LIQUOR
PHENOL RECOVERY (PHENOSOLVAN)
76
FILTER BACKWASH
AMMONIA RECOVERY
82
CLEAN GAS LIQUOR
STEAM AND POWER GENERATION
86
BOILER BLOWDOWN
RAW WATER TREATMENT
41
FILTER BACKWASH AND BRINES
PROCESS COOLING
95
COOLING TOWER BLOWDOWN

Figure 3-2. Process Modules Generating Aqueous Wastes in an Integrated Lurgi SNG Facility (stream numbers refer to Figures 2-2, 2-3 and 2-4; see Table 2-1 for index to streams)

3.6.2 Coal Gasification

An ash quench slurry results when process waters are used to cool and transport gasifier ash to a settling unit or disposal site. The nature of the ash quench slurry depends upon the characteristics of both the hot gasifier ash and the process water used for quenching. (The composition of typical Lurgi ashes are presented in Table 3-25, Section 3.7.) No operating data are available for ash quench slurry characteristics. Data from laboratory experiments simulating the ash quenching operation, however, are available and are presented in Table 3-18. The data shown are for the composition of 10% Lurgi ash slurry supernatants resulting from contacting an Illinois No. 6 coal ash with water at various pH levels. The supernatants contain moderate levels of total dissolved solids (around 1000 mg/l) with the dominant ions being Ca^{++}, SO_4^{--}, K^+ and Na^+. As indicated by the data in Table 3-18, elements other than Ca, Mg, Na and K tend to be relatively insoluble under the natural alkaline conditions of the ash supernatants (i.e., without the addition of acid or base); some increase in solubility is observed with decreasing pH (e.g., Fe, Mn, Cd, Al). About 1% by weight of the ash for the Illinois No. 6 coal is apparently readily soluble in the supernantant. As indicated by the values for oil and grease and COD, a small amount of organic residue may be associated with the Lurgi ash. The use of an inert atmosphere instead of air apparently does not have a pronounced effect on the solubility of the substances measured.

The ash slurry supernatants for the Illinois No. 6 coal have been tested for toxicity to fathead minnows(36). The results of these bioassay tests indicate that the constituents in equilibrium with the ash at near neutral pH levels are not acutely toxic to young fathead minnows. Supernatants obtained under alkaline and acidic pH's, however, show high acute toxicity; neutralized samples of the supernatants also show high acute toxicity. Both pH and total salt content were determined to be important factors affecting acute toxicity.

Lurgi ash from the experimental gasification of Mercer County, North Dakota lignite at SASOL, South Africa has also been subjected to leaching tests(13). Based on these tests and tests with laboratory ash from Dunn County lignite samples, the leachability of the Dunn County lignite ash produced by the proposed ANG Lurgi facility has been estimated. Table 3-19 presents the solubility estimates in terms of the percentage of an element which would be

TABLE 3-18. CHEMICAL COMPOSITION OF LURGI ASH SLURRY SUPERNATANT(36)*

Exposure atmosphere	Air				Argon			
pH	7.55	5.10	3.82	2.68	8.2	7.20	5.35	3.79
Parameter/Constituent								
Conductivity (μmhos/cm)	1170	1500	1950	5600	1200	1390	1800	5200
COD (mg/l)	2	2	2	81	2	2	16	140
Oil & grease (mg/l)	28	28	0	23	10	3	6	4
Cl^-	ND†	ND	ND	ND	ND	ND	ND	ND
Ca^{++} (mg/l)	290	480	400	570	440	370	430	500
Mg^{++} (mg/l)	10.5	14	15	22	9.5	11	13.5	23
NH_4^+ (mg/l)	17	8	12	11	10	10	10	17
$SO_4^=$	820	943	808	38	730	735	700	710
K^+	42	49	51	26	39	43	48	61
Na^+	[illegible]	37	38	40	32	37	37	40
B	4.0	4.5	4.5	5.5	4.5	3.0	4.5	8.0
Cu	0.01	0.02	0.13	0.73	0.01	0.05	0.01	0.05
F^-	0.31	0.30	0.09	0.04	0.51	0.34	0.16	0.02
Fe (total)	0.06	0.19	0.24	560	0.06	0.11	101	860
Si	5	29	60	130	4	9	27	120
Li+	1.8	1.9	2.0	2.0	1.6	1.8	1.9	2.1
Mn++	0.45	1.94	2.7	3.8	0.11	0.90	2.3	3.7
Cd	0.02	0.03	0.03	0.06	0.01	ND	0.02	0.05
Ni	0.03	0.13	0.23	0.50	ND	0.04	0.14	0.42
Pb	0.1	0.1	0.1	0.2	ND	ND	0.1	0.2
Sb	0.2	0.3	0.3	0.6	0.3	0.3	0.3	0.5
Sr	1.8	1.9	2.1	2.9	1.5	1.7	1.9	2.6
Zn	0.12	5.5	12	17	0.01	0.4	6.3	20
Al	ND	2	14	132	ND	ND	ND	92
As	ND	ND	ND	ND	ND	ND	ND	ND
Be	ND	ND	0.01	0.03	ND	ND	ND	0.01
Cr	ND	0.02	0.05	0.12	0.01	0.01	0.06	0.16
Co	ND	0.05	0.08	0.19	ND	ND	ND	0.17
Mg	ND	ND	ND	ND	ND	ND	ND	ND
Mo	ND	ND	ND	ND	ND	ND	ND	ND
Al	ND	ND	ND	ND	ND	ND	ND	ND
Te	ND	ND	ND	ND	ND	ND	ND	ND
$S^=$	ND	ND	ND	ND	ND	ND	ND	ND

*Slurry containing 10% ash from Illinois No. 6 coal, except for pH values of 7.55 and 8.2 which are the "natural" pH of the supernatant, the supernatant pH adjusted to indicated levels.

†ND = not detectable

TABLE 3-19. ESTIMATED SOLUBILITY OF ELEMENTS IN LURGI ASH FROM GASIFICATION OF DUNN COUNTY, NORTH DAKOTA LIGNITE(13)

Element	Percent of Element Leachable*	Quantity of Element Solubilized,* kg/tonne (lbs/ton) of Ash	Estimated Maximum Concentration of Elements in Ash Slurry Supernatant† (mg/l)
Al	0.32	0.15 (0.29)	87
As	0.74	0.0005 (0.001)	0.3
B	15.9	0.0015 (0.003)	41
Ba	<0.09	<0.0001 (<0.003)	0.8
Br	13	0.0015 (0.003)	0.9
Ca	0.49	0.53 (1.06)	321
Co	1.6	0.0005 (0.001)	0.3
Cr	4.4	0.02 (0.04)	11
Cs	42	0.005 (0.001)	0.4
Cu	7	0.01 (0.02	6
F	4.5	0.005 (0.01)	2.6
Ga	5.4	0.0015 (0.003)	1
Ge	<1.3	<0.0005 (<0.001)	0.03
Fe	<0.4	<0.2 (<0.4)	<100
Hg	4.4	<0.0005 (<0.001)	<0.0001
K	21	0.7 (1.3)	395
Li	11	0.001 (0.002)	0.6
Mn	<0.25	<0.005 (<0.01)	<3
Mo	92	0.11 (0.23)	71
Ni	1.4	0.001 (0.002)	6
Na	37.1	5.9 (11.7)	3500
P	<0.5	<0.005 (<0.01)	<3
Pb	0.31	<0.0005 (<0.001)	0.06
Rb	59	0.015 (0.03)	10
S	84	8.7 (17.3)	5231
Sc	<0.66	<0.0005 (<0.001)	<0.2
Se	<34	<0.0005 (<0.001)	<0.17
Sr	0.71	<0.05 (0.1)	30
Ti	<2.3	<0.05 (<0.1)	<25
W	24	<0.001 (<0.002)	<0.6
V	5.2	<0.001 (0.002)	4.7
Zn	37	0.002 (0.004)	1.2

*Estimated for Dunn County lignite ash based on data for Mercer County lignite gasified in Lurgi gasifier at SASOL, South Africa.

†Assuming that ash slurry contains 0.6 kg ash/kg water.

leachable, the quantity which would be leached out (kg/tonne of ash) and the maximum concentration (mg/l) of the element in the ash supernatant. The major water soluble elements are Na, K, and S (as $SO_4^=$). For these elements, the total quantity solubilized amounts to about 1% by weight of the ash (a value close to that obtained in leaching tests using ash from Illinois No. 6 coal). Several other elements, although present in the ash at much lower levels than Na, K, and S, also show considerable solubility in water. These elements include B, Br, Cs, Li, Mo, Se, Rb, W and Zn. The maximum concentration values listed in the last column in Table 3-19 are calculated values for the proposed ANG gasification facility, assuming that all water leachable components of the ash were released to the water used for ash transport. Such a total release of the leachable components can result in a relatively high concentration of total dissolved solids (about 20,000 mg/l). In addition, the concentration of certain hazardous elements (e.g., As, Ni, Cr and Cu) would reach levels which would warrant concern for discharge of ash slurry water to receiving waters.

Process waters used in a commercial Lurgi facility to quench ash may contain organic substances such as phenols, fatty acids and polycyclic aromatics, and inorganic ions such as SCN^-, CN^- and $S^=$. The alkaline ash may adsorb or effect precipitation of some of these substances. Substances such as CN^- and phenols in quench water may also enhance the solubility of certain metals contained in the ash via complex formation. At present there are insufficient data to accurately define the characteristics of quench waters which would be generated in a commercial Lurgi facility.

3.6.3 Gas Purification

Lurgi Gas Liquor. Raw gas liquor collected from primary and secondary cooling units is processed for tar and oil recovery. Available data for the gas liquor stream relate to the aqueous phase after tar and oil separation. Tables 3-20 and 3-21 present data for separated gas liquor. Data on the separated tars and oils were presented in Tables 3-11 and 3-12. As shown in Table 3-20, from 1 to 2.6 kg of separated gas liquor are generated per kg of coal depending on the coal moisture and amount of steam used for gasification. The separated gas liquors contain large amounts of dissolved and suspended organics as reflected by the high BOD, COD and suspended tar and oil values. The inorganic component of gas liquor consists primarily of ammonia and bicarbonate with smaller amounts of sulfide, thiocyanate and cyanide.

TABLE 3-20. MAJOR CONSTITUENTS AND GROSS PARAMETERS FOR SEPARATED LURGI GAS LIQUORS*

Coal No.† (Reference)	1 (7)		2 (7)		3 (7)		4 (7)		5 (44)	5 (56)
Production Rate, kg/kg	0.93		2.11		1.77		2.60		1.06	--
Suspended Tar & Oil	350	650	1130	2150	2150	2200	300	1100	5000	--
Analysis on tar free basis	Inlet tar sep.	Inlet oil sep.	Inlet tar sep.	Inlet oil sep.	Inlet tar sep.	Inlet oil sep.	Inlet tar sep.	Inlet tar sep.	--	--
pH	9.6	8.3	9.8	8.5	9.5	8.3	9.3	8.2	--	8.9
T.D.S.	4030	1765	2770	1570	3180	1120	1550	1240	--	2460
T.D.S. after ignition	45	35	110	35	85	25	105	120	--	--
Sulfide	130	115	25	440	15	490	65	520	--	<0.5
Total S	150	265	180	730	160	930	155	720	--	--
Fatty acids	1250	1670	490	280	400	260	275	610	300	--
Ammonia										
Free: ppm	3990	14015	1700	17650	1520	13970	1600	14000	10,600	11,200
Fixed: ppm	395	525	280	210	410	330	320	250	150-200	--
Carbonate	4070	19460	1280	6500	680	9210	1360	10740	8500	--
Total phenols	4200	4406	2200	1900	2900	3750	1400	2150	3250-4000	--
Monohydric phenols	--	--	--	--	--	--	--	--	--	2410
Cyanide	2	4	3	11	7	14	1	12	6	--
Thiocyanate	6	15	65	160	79	158	70	185	--	85
Cl	45	40	135	75	290	170	240	210	--	--
BOD	9900	13400	3800	4700	6000	6200	4100	5400	--	--
COD	22700	20800	10100	12000	9300	10600	650	7500	--	12,500
TOC	--	--	--	--	--	--	--	--	--	4190

*All units are mg/l except pH and production rate

†Coal numbers refer to those in Table 3-1

Table 3-21 summarizes available data on the trace element composition of the separated Lurgi gas liquors. Some elements (e.g., As, B, Cd, F, Hg and V) are found at levels which could require removal before discharge. The fractions of various elements which exist in soluble and suspended form are not known at present.

Limited data are available for organics contained in Lurgi gas liquors. The data include those presented in Table 3-13 relating to the phenolics composition in the gas liquor. Table 3-22 presents the levels of three classes of organics in one sample of Lurgi gas liquor from SASOL, South Africa. (The data on the characteristics of clean gas liquor are also presented in this table; these data will be discussed in connection with clean gas liquor.) Monohydric phenols are seen to comprise a significant fraction of the measured organics, with fatty acids and aromatic amines comprising about equal but much smaller fractions. In the table, the theoretical COD and TOC values have been calculated to estimate the percentage of total organics accounted for by monohydric phenols, fatty acids, and aromatic amines. Based upon the measured COD and TOC values of 12,500 and 4190 mg/1, respectively, for this wastewater sample, about 50% of the total COD and TOC are represented by the compounds listed in the table. Of the remaining 50% of organics approximately half would likely be represented by the polyhydric class of phenols (see Tables 3-13 and 3-20 for the relative concentrations of the monohydric and polyhydric classes of phenols). The polycyclic aromatic hydrocarbons and heterocyclics, aromatic acids and aldehydes probably comprise the bulk of the remaining organics.

Rectisol Methanol/Water Still Bottoms. Recovery of naphtha and methanol from condensates in the Rectisol process is accomplished by azeotropic distillation. Tables 3-23 presents available data on the characteristics of this stream from the Lurgi facility at SASOL, South Africa. The still bottoms contain mostly water with small amounts of less volatile organics and methanol. Inorganics such as sulfide, thiocyanate, and ammonia are also present in small concentrations. The specific flow rate and composition of this stream in an SNG facility will depend largely upon the Rectisol design employed. For example, in the design for the El Paso Burnham Lurgi facility, the flow rate for this stream is about one-third that for the SASOL facility(31). Because of its relatively small volume in a commercial facility the still bottoms would likely be combined with other waste streams (e.g., clean gas liquor) for treatment.

TABLE 3-21. MINOR AND TRACE ELEMENT COMPOSITION OF SEPARATED LURGI GAS LIQUORS

Coal Number* (Reference)	1 (14)	6 (13)	9 (15)
Coal Type/Origin	Subbituminous Rosebud Montana	Lignite N. Dakota	Lignite N. Dakota
Liquor Production Rate (kg/kg) dry basis	0.93	1.53	1.53
Element (mg/l.)			
Al	--	2.9	--
Ca	--	14.6	--
Fe	--	0.2	--
K	--	0.8	--
Na	--	82.5	--
Si	--	117	--
Ti	--	0.02	--
Mg	--	0.6	--
Ag	0.017	--	0.2
As	0.014	0.1	3
B	5.3	0.9	3
Ba	0.001	0.005	--
Ge	0.22	--	0.008
Br	--	0.001	--
Cd	0.1	0.2	0.03
Ce	--	0.006	--
Co	0.001	0.001	0.03
Cr	1.3	0.02	0.03
Cu	1	0.02	0.3
F	19	5	0.5
Hg	0.056	0.17	0.003
Li	0.9	0.002	0.02
Mo	0.01	0.04	0.2
Mn	0.01	0.03	--
Ni	0.5	0.006	0.2
P	--	6	--
Pb	0.12	0.005	0.2
Rb	--	0.003	--
Sb	0.002	--	0.03
Sc	--	0.006	--
Se	0.05	0.004	2
Sn	0.45	--	0.03
Sr	--	0.004	--
U	0.15	--	0.2
V	2.5	0.001	0.003
Y	--	0.004	--
Zn	0.06	0.2	0.4
Zr	--	0.008	--

*Coal numbers refer to those in Table 3-1.

TABLE 3-22. CONCENTRATION OF ORGANIC COMPOUNDS AND THEIR EQUIVALENT COD AND TOC VALUES FOR THE SEPARATED AND CLEAN LURGI GAS LIQUOR AT SASOL, SOUTH AFRICA(56)

	Separated Gas Liquor			Cleaned Gas Liquor		
Compound	mg/l	COD	TOC	mg/l	COD	TOC
Fatty Acids						
Acetic Acid	171	183	68.4	123	131.6	49.2
Propanoic Acid	26	39.3	12.7	30	45.3	14.7
Butanoic Acid	13	23.7	7.8	16	29.1	9.6
2-Methylpropanoic Acid	2	3.8	1.1	5	9.5	2.7
Pentanoic Acid	12	24.5	7.1	7	14.3	4.1
3-Methylbutanoic Acid	1	2.1	0.6	5	10.5	2.9
Hexanoic Acid	1	2.2	0.6	8	17.7	5.0
	226	278.6	98.3	194	258	88.2
Monohydric Phenols						
Phenol						
2-Methylphenol	1,250	2,975	963	3.2	7.6	2.5
3-Methylphenol	340	857	265	< 0.2	<0.5	<0.2
4-Methylphonel	360	907	277	< 0.2	<0.5	<0.2
2, 4-Dimethylphenol	290	731	226	< 0.2	<0.5	<0.2
3, 5-Dimethylphenol	120	314	95	NF	--	--
	<50	<131	<39.5	NF	--	--
	2,410	5,915	1866	3.2	9.1	3.1
Aromatic Amines						
Pyridine	117	261	88.9	0.45	1.0	0.34
2-Methylpyridine	70	169	53.9	<0.05	<0.12	<0.04
3-Methylpyridine	26	62.7	20.0	<0.05	<0.12	<0.04
4-Methylpridine	6	14.5	4.6	<0.05	<0.12	<0.04
2, 4-Dimethylpyridine	<1	<2.5	<0.8	NF*	--	--
2, 5-Dimethylpyridine	<1	<2.5	<0.8	NF	--	--
2, 6-Dimethylpyridine	<1	<2.5	<0.8	NF	--	--
Aniline	12	28.9	9.2	NF	--	--
	231	544	179	0.45	1.4	0.5
Total	2,867	6,738	2,143	198	269	92

*NF = not found

TABLE 3-23. CHARACTERISTICS OF RECTISOL METHANOL/WATER STILL BOTTOMS FOR LURGI FACILITY AT SASOL, SOUTH AFRICA(44)

Stream Flow Rate liters/10^3 Nm^3 of feed gas (gal/1000 scf)	42 (0.31)
pH	9.7
Phenol (mg/l)	18
CN^- and SCN^- (mg/l)	10.4
NH_3 (mg/l)	42
$S^=$ (mg/l)	Trace
COD (mg/l)	1606
Conductivity (μmhs/cm)	1111

3.6.4 Gas Upgrading

Condensates produced during methanation and drying are the only aqueous wastes associated with gas upgrading. These wastes are expected to be very low in dissolved and suspended solids. Dissolved gases such as methane, CO, and CO_2 will be present but these gases would ordinarily be flashed from the condensate and added to product SNG. Dehydration condensate may contain traces of glycol depending on the design of the system. No data are currently available to indicate the characteristics of this stream(s) from a commercial operation.

3.6.5 Auxiliary Processes

Phenosolvan Filter Backwash. No data are currently available for this stream. This stream, however, is expected to contain tarry/oily substances and coal/ash fines which are removed from the separated gas liquor.

Clean Gas Liquor. In the designs for all proposed Lurgi SNG facilities the Phenosolvan process is used for the removal/recovery of phenols from separated gas liquor. Ammonia and H_2S are subsequently removed from the dephenolized gas liquor by steam stripping. The ammonia in the stripper overhead is recovered by one of several licensed processes. One such process, the Chemie Linz AG/Lurgi process, is licensed by Lurgi.

Table 3-24 presents typical data on the characteristics of the separated and clean gas liquor for a system employing the Phenosolvan process (using

TABLE 3-24. PROPERTIES OF SEPARATED AND CLEAN GAS LIQUOR AT THE SASOL PHENOSOLVAN PLANT*

Parameter/Constituent	Separated Gas Liquor	Clean Gas Liquor†	
	Reference 43	Reference 43	Reference 55
Total Phenols	3250 - 4000	160	--
Steam Volatile Phenols	--	1	--
COD	--	1126	1330
Fatty Acids (as CH_3COOH)	300	560	--
Total Suspended Solids	--	21	--
Total Dissolved Solids	--	875	596
Suspended Tar and Oil	5000	21	--
Total Ammonia	10800	215*	150
Total Sulfide	228	12*	<0.5
Cyanide	6	1	--
Thiocyanate	85	--	80
Fluoride	--	56	--
Chloride	--	25	--
Sodium	53	--	--
Calcium	--	18	--
Iron	--	1	--
Ortho Phosphate	--	2.5	0.2
Conductivity (μmhos/cm)	--	1000 - 1800	--
Total Organic Carbon	--	--	--
pH	--	8.4	8.2

*Except for pH and conductivity, all units are in mg/l

†Dephenolized gas liquor is steam stripped to remove H_2S and ammonia. The stripping process is not usually considered part of the basic Phenosolvan process.

butyl acetate as the extraction solvent) followed by steam stripping for ammonia and H_2S removal. As indicated by the data about 90% removal of COD, 96% removal of total phenols, 95 to 98% removal of ammonia and 95% removal of H_2S is achieved by the combined extraction/stripping processes. Although steam stripping is expected to remove the Phenosolvan solvent from the aqueous phase, a few ppm of solvent will be present in the clean gas liquor. Proposed commercial facilities in the U.S. are to use isopropyl ether rather than butyl acetate as the extraction solvent. One design expects 99.5% removal of monohydric phenols, 60% removal of polyhydric phenols, and 15% removal of other organics(31). Actual operating data for the Phenosolvan process using isopropyl ether and for the Chemie Linz AG/Lurgi ammonia recovery process are currently unavailable. Data for other stripping/ammonia recovery processes are discussed in Section 4.3.

Boiler Blowdown. Boiler feedwater is generally demineralized to minimize scale formation in boiler tubes. Blowdown is necessary to maintain a certain desired dissolved solids level, which is dictated by the pressure of steam generated. Boiler blowdown will contain dissolved solids and small amounts of phosphate and amines used to inhibit deposit formation and corrosion. No actual data are available for boiler blowdown associated with Lurgi systems, but the quantities and composition of this stream are expected to be similar to those encountered in other boiler applications.

Cooling Tower Blowdown. Cooling tower blowdown will contain high levels of total dissolved solids (TDS), treating chemicals and components of treated plant wastewaters if such waters are used as makeup. TDS levels of less than 10,000 are usually required to inhibit precipitation of salts in the tower. Additives to cooling water will accumulate and appear in the blowdown. One estimate of the concentration of such additives in cooling tower feedwater associated with a Lurgi facility indicates 300 to 500 ppm chromates, 20 to 50 ppm total phosphate and 300 to 400 ppm chlorinated phenols(46). The concentration of these substances in the blowdown may be several times those in the feedwater. Sulfuric acid is commonly added to cooling water to inhibit calcium scale formation and will result in high sulfate levels in the blowdown.

If treated plant waters are used as cooling tower makeup, the blowdown will contain some of the constituents of these waters. In the El Paso Burnham design, the clean gas liquor is to be used as the cooling tower makeup; such makeup water is expected to contain approximately 760 ppm total phenol, 2700 ppm fatty acids and 200 ppm ammonia. Some degradation of organics and volatilization of ammonia and H_2S are expected in the cooling tower, although little operating data are currently available to indicate the extent of degradation/ volatilization.

Raw Water Treatment Filter Backwash and Brines. Filter backwash from rapid sand filters used in raw water treatment generally contains soil-derived sediment. The water is clarified by settling and the solids disposed of in a landfill. The solids and clarified water are usually considered as relatively innocuous materials. Brines generated by water softening and demineralization contain high concentrations of salts, primary chlorides and sulfates of sodium and calcium and to a lesser extent, potassium and magnesium.

Although no data are available for these wastes in SNG facilities, their characteristics are not expected to be different from those of analogous wastes in other industries (e.g., steam-electric power production) and are not unique to SNG production.

Misceallenous Plant Wastewater. Included in this category of wastewaters are plant and coal pile runoff, and sanitary wastewater. Runoff from the plant site and adjacent storage areas can contain high levels of suspended solids and organics. The characteristics of such waters would be highly variable, depending on stream frequency and duration, and the nature and quantities of materials and surfaces which the water contacts. No data are currently available on this type of stream associated with a Lurgi facility.

Sanitary wastewater would be generated at any industrial facility and would require treatment by conventional techniques.

3.7 SOLID WASTES

Process modules generating solid wastes in Lurgi systems are depicted in Figure 3-3. Identified are eight types of wastes: (1) coal preparation wastes (Streams 2, 3 and 4), (2) gasifier and boiler ash (Streams 12 and 63), (3) spent catalysts (Streams 25 and 30), (4) methanation guards (Stream 48), (5) by-product storage sludges and solids (Stream 96), (6) spent filter media from the Phenosolvan process (Stream 55), and (7) solids and sludges from raw water (Streams 39, 49 and 53). The available data on the characteristics of these wastes are presented below. Streams generated by pollution control processes are reviewed in Section 4.4.

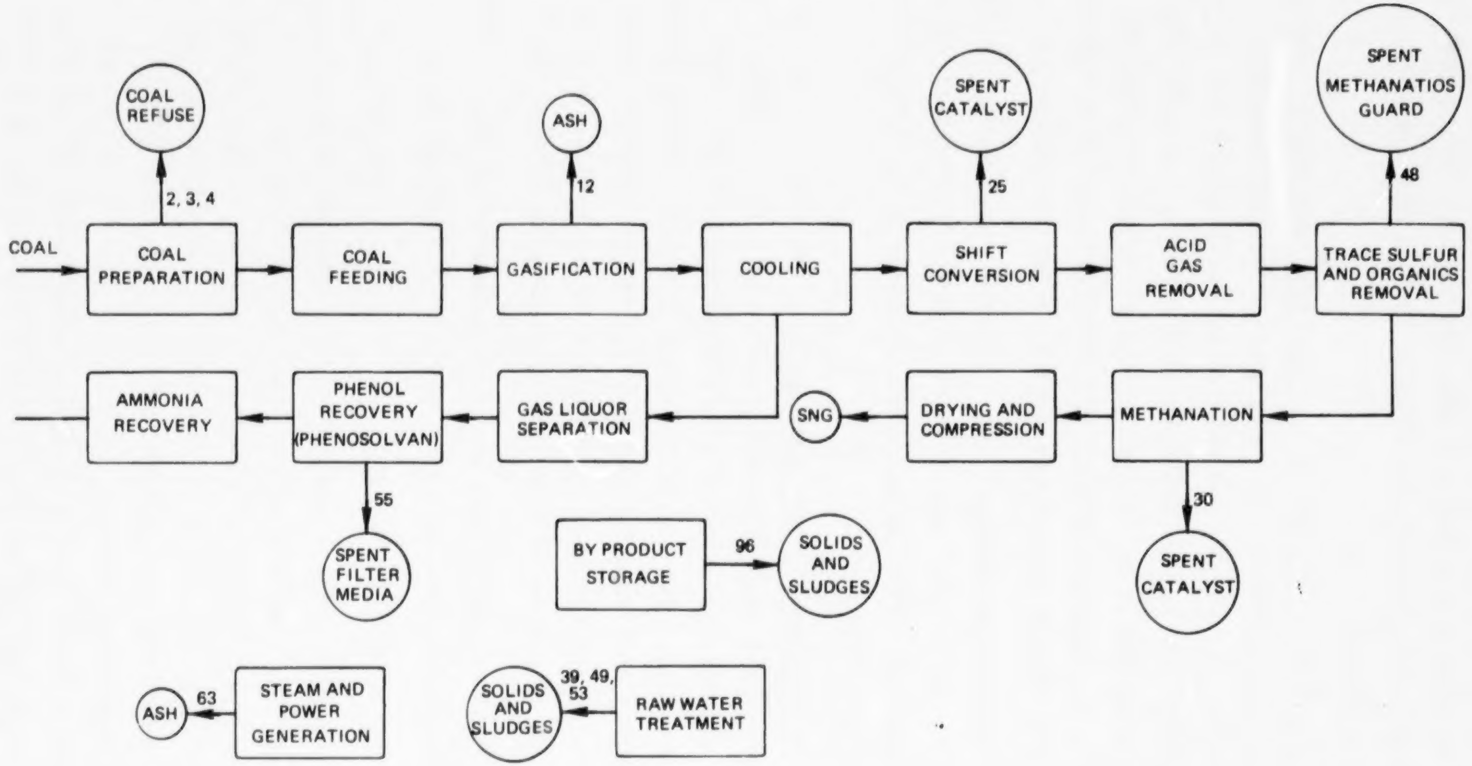

COAL
COAL PREPARATION
2, 3, 4
COAL REFUSE
COAL FEEDING
GASIFICATION
12
ASH
COOLING
SHIFT CONVERSION
25
SPENT CATALYST
ACID GAS REMOVAL
TRACE SULFUR AND ORGANICS REMOVAL
48
SPENT METHANATIOS GUARD
METHANATION
30
SPENT CATALYST
DRYING AND COMPRESSION
SNG
GAS LIQUOR SEPARATION
PHENOL RECOVERY (PHENOSOLVAN)
55
SPENT FILTER MEDIA
AMMONIA RECOVERY
BY PRODUCT STORAGE
96
SOLIDS AND SLUDGES
STEAM AND POWER GENERATION
63
ASH
RAW WATER TREATMENT
39, 49, 53
SOLIDS AND SLUDGES

Figure 3-3. Process Modules Generating Solid Wastes in Lurgi SNG Systems

3.7.1 Pretreatment and Handling

Coal fines, refuse and collected fugitive dusts are the solid wastes associated with the coal preparation operation. Coal fines resulting from screening of crushed feed may either be used directly as boiler fuel or be cleaned for sale. In the latter case, a refuse is generated which contains mostly inerts and some coal. The use of fabric filters for dust collection in crushing/screening operations will also generate a solid waste containing coal fines and inerts. The average particle size of this waste will be smaller than that generated by coal cleaning. Although no characterization data are available for these wastes, they are expected to be similar to the gross composition of run-of-mine coal shown in Table 3-1.

3.7.2 Coal Gasification

Characterization data available for ashes from the Lurgi gasification are shown in Table 3-25 for several coals. These analyses represent ash before quenching with water for cooling and transport and therefore do not reflect loss of solubilized material to wastewater. (The solubility of the ash components of Illinois and No. Dakota coals were discussed in Section 3.6.2). Generally, Lurgi ash contains the bulk of the inorganic component of the feed coal and about 2 to 8% residual carbon. Some of the original coal sulfur is also retained with the ash. Volatile trace elements such as Hg, Se, Te and As may be partially lost during gasification.

3.7.3 Gas Purification

Zinc oxide used as methanation guard will require periodic replacement. Spent guard material will consist primarily of zinc sulfide and unreacted zinc oxide. No operating data are available on the quantity and composition of the spent methanation guard at present.

3.7.4 Gas Upgrading

Catalysts used for shift and methanation require periodic replacement; the spent catalysts constitute a solid waste. Gross composition of spent catalyst is not expected to be dramatically different than that of fresh catalyst, although accumulation of carbon, sulfur, and metallic elements is to be expected. No data are available on the characteristics of spent catalysts from Lurgi SNG systems. Data on spent methanation catalyst from pilot scale SNG

TABLE 3-25. ELEMENTAL COMPOSITION OF ASH PRODUCED BY GASIFICATION OF VARIOUS COALS IN LURGI GASIFIERS

Coal Number*	1	2	2	3	4	5	6	6
Coal Type/Origin	Subbituminous Montana/Rosebud	Bituminous Illinois #6	Bituminous Illinois #6	Bituminous Illinois #5	Bituminous Pittsburgh #8	Bituminous So. African	Lignite N. Dakota	Lignite N. Dakota
Source of Data	(7,14)	(7,42)	(36)	(7,14)	(7)	(34)	(15)	(13)
Production Rate, kg/kg (dry basis)	0.12	0.10	--	.092	.081	0.31	0.1	0.1
Major Elements (%)								
Al_2O_3	17.7	20.5	20.5	18.1	20.7	28	--	24
CaO	8.3	2.1	2.3	3.9	3.0	7	--	26
Fe_2O_3	11.2	17.2	20.5	19.7	15.0	5	--	11
K_2O	--	--	1.8	--	--	--	--	0.6
MgO	3.9	1.0	0.6	0.7	0.7	1.7	--	7
Na_2O	--	--	0.3	--	--	--	--	8
SiO_2	46.8	49.6	49.3	46.1	43.6	52	--	25
TiO_2	--	--	1.0	--	--	--	--	0.6
SO_3	1.7	1.3-1.5	1.5	0.6-1.2	0.8	0.2	--	3.1
C	6.5	3.2-5.4	--	2.0-3.8	7.6	--	--	--
N	--	0.05	--	0.04	--	--	--	--
Cl	150	--	0.01	--	--	.01	--	.007
Trace Elements (ppm)								
Ag	-.23	--	<0.4	--	--	--	0.7	1
As	26	0.1	3	0.3	--	1-2	60	74
B	380	622	355	673	--	100-150	<1500	1680
Ba	1900	--	950	--	--	--	12000	8270
Be	2.8	14	12	20	--	<.05	5	6
Br	--	--	<1	--	--	<.1	--	3
Cd	2.4	<0.3	<1.6	0.3	--	<0.1	<1	0.5
Ce	--	--	140	--	--	200-400	--	190
Co	4.3	0.4	34	0.4	--	--	10	13
Cr	440	750	212	592	--	--	40	140
Cs	--	--	11	--	--	--	--	.9
Cu	130	239	57	273	--	--	50	27
F	600	5	<10	5	--	150	230	191
Ga	--	--	26	--	--	--	--	53
Ge	--	--	7	--	--	--	--	2
Hg	.03	.04	.05	.016	--	--	<.1	.055
Li	85	--	42	--	--	--	60	45
Mo	200	6	30	8	--	--	4	12
Mn	790	200	1859	305	--	2000	--	760
Ni	200	456	89	452	--	150-200	25	25
P	--	--	87	--	--	--	--	3500
Pb	40	96	45	200	--	50	200	58
Rb	--	--	162	--	--	--	--	35
Sb	6.2	0.2	4.2	19	--	<0.5	1	33
Sc	--	--	29	--	--	--	--	4
Se	2.2	--	<1	--	--	--	1.5	0.5
Sh	3.7	--	--	--	--	--	12	4
Sr	--	--	370	--	--	--	--	12,900
Te	--	--	--	--	--	--	--	0.3
U	13	--	17	--	--	--	6	7
V	91	301	184	181	--	1000	70	150
W	--	--	1.5	--	--	--	--	2
Y	--	--	--	--	--	--	--	320
Zn	32	--	400	--	--	--	0.5	10
Zr	--	469	170	1600	--	--	--	520

*Coal numbers refer to those in Table 3-1.

production at the Hygas pilot plant in Chicago are presented in Table 3-26.

TABLE 3-26.* ANALYSIS OF SPENT METHANATION CATALYST FOR THE PILOT PLANT(57)

Parameter/Constituent	First Stage		Second Stage		Typical Fresh Catalyst
	Bottom	Top	Bottom	Top	
Sulfur, %	3.7	0.95	0.13	0.16	0.15
Carbon, %	3.4	4.7	5.3	4.5	3.4
Nickel, %	52	61	60	61	60
Surface Area, m^2/g	36	69	75	79	150
Total Pore Volume, cc/g	0.16	0.27	0.27	0.27	0.25
Ni Crystallite Size, A	491	97	89	99	65

*Catalyst type: Harshaw Ni-0104-T-1/4

3.7.5 Auxiliary Processes

Spent Filter Media from the Phenosolvan Process. In the Phenosolvan process, filtration is used to remove suspended materials from the process feed (the separated gas liquor). At the SASOL, South Africa plant the filtration is carried out through a bed of sand. Although no data are available to indicate a periodic need for the replacement of the bed material, it is very likely that such replacement would be necessary in a commercial facility due to accumulation of tarry material in the feed which would irreversibly plug the filter pores. The characteristics of the spent bed including the required replacement frequency are not known.

Solids and Sludges from By-Product Storage. Storage of Lurgi by-product liquids (tars, oils, phenols and naphtha) may result in the generation of bottom sludges. The nature or quantity of each sludge would depend upon the material stored, its purity, length of storage and storage temperature. No actual data are available on such solids and sludges from Lurgi systems.

Solids and Sludges from Raw Water Treatment. Sludges containing lime, alum, and sediment would be generated as a result of raw water treatment in most Lurgi SNG facilities. The quantities and characteristics of such sludges would depend upon the nature of the raw water treated and would not be unique to coal gasification. No operating data are currently available for this stream in a Lurgi SNG plant.

Ash from On-Site Steam and Power Generation. When coal is burned directly or gasified in air blown gasifiers to produce fuel gas for on-site steam and power generation, ash will be produced as a waste product. In either case, the ash(es) will have overall compositions similar to those shown in Table 3-25 for the Lurgi ash. Combustion ash would be expected to have essentially no residual carbon, to be more alkaline, and be more depleted in volatile trace elements when compared to gasification ash.

4.0 PERFORMANCE AND COST OF CONTROL ALTERNATIVES

Many of the pollution control technologies which would be applicable to waste streams identified in Chapters 2 and 3 represent adaptations of the technologies which are currently used or are under development for use in such related industries as petroleum refining, coal cleaning, by-product coke, and electrical utilities. This chapter provides (1) a review of the control methods which may be adapted from other industries and from general pollution control practice, (2) a definition of limitations of and necessary modifications to these control methods for use in coal gasification plants, (3) a discussion of those controls which have actually been demonstrated in coal gasification plants, and (4) an identification of control technologies which are under development for these and similar applications. Control alternatives evaluated include material and process changes in addition to "add on" controls.

4.1 PROCEDURES FOR EVALUATING CONTROL ALTERNATIVES

The various control technologies applicable to the management of each of the waste streams identified in Chapters 2 and 3 were evaluated. Based on these evaluations, a limited number of pollution control options for use in integrated plants were selected and examined from the standpoint of total plant emissions, costs and energy requirements. The flow diagrams and engineering assumptions/calculations which provide the basis for arriving at these estimates are presented in Appendices B and C.

The evaluation of the control technologies for application to individual waste streams was based on considerations of control efficiency, ability to comply with emissions regulations, energy and resource consumption, reliability, simplicity, multi-pollutant abatement capability, residue generation and disposal requirements, potential for recovery of by-products, capital and operating costs and stage of development. The above criteria were used as a basis for comparison of candidate control technologies, used alone or in combination with in-plant control methods or other add-on controls, and identification of tradeoffs in control technologies for minimizing total plant waste emissions and energy requirements.

4.2 AIR EMISSIONS CONTROL ALTERNATIVES

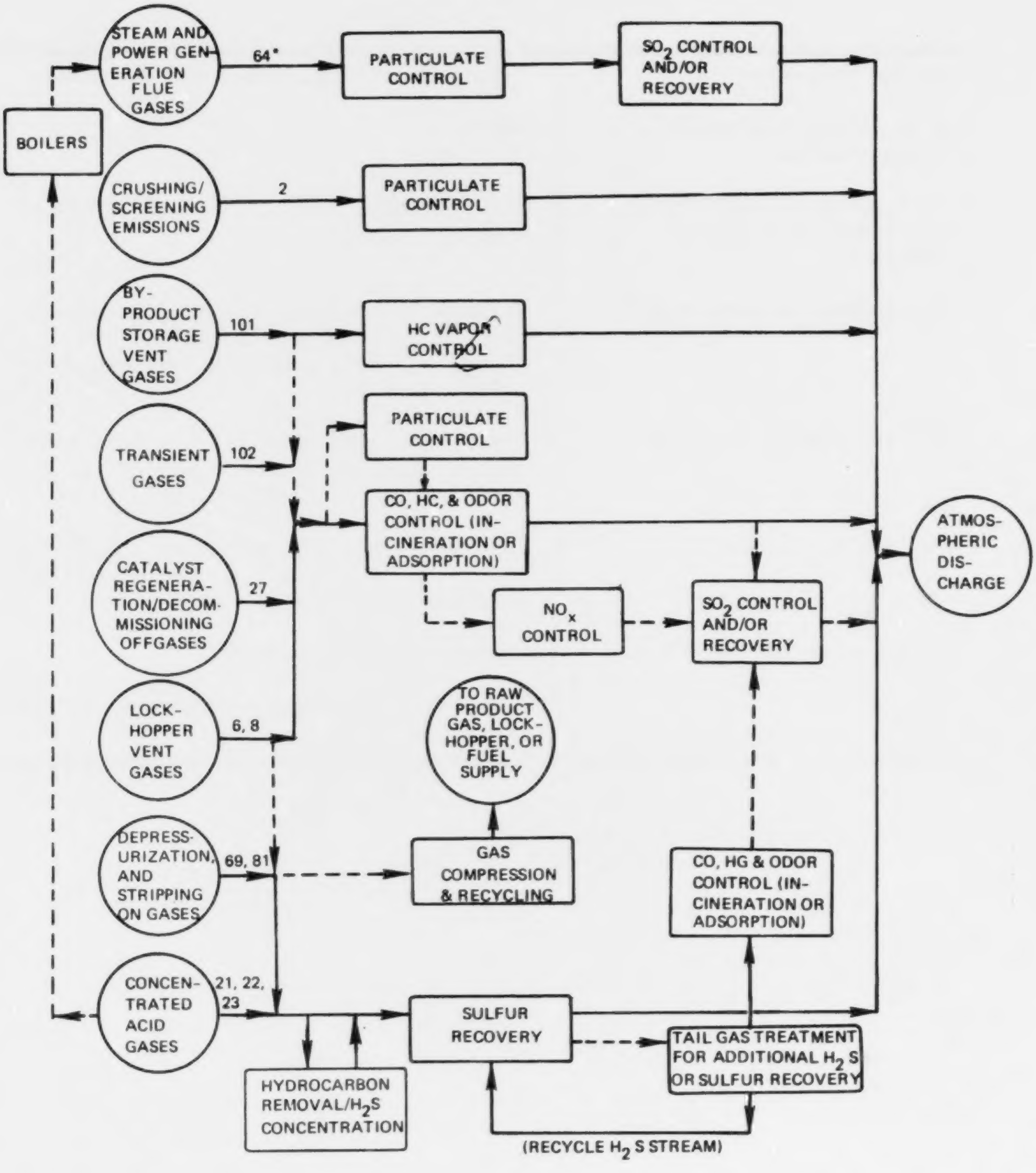
Since no commercial Lurgi SNG facilities currently exist in the United States, no operating data are available on many of the processes which may be employed in such facilities to control gaseous emissions. Only a few of the control processes have been tested in coal gasification application. Many of the control processes, however, have been used in similar applications in other industries (primarily in the petroleum refining and natural gas industries). In this section, the air pollution control processes which have been tested in coal gasification applications or which may be potentially suitable for such applications are reviewed. A summary of the most effective air emissions control alternatives is given in Section 4.6.

Figure 4-1 shows the process modules for the control of waste gases identified in Chapters 2 and 3. The process modules shown in the figure are sulfur recovery; tail gas treatment (for additional H_2S or sulfur recovery); SO_2 control and/or recovery; incineration; particulate control; CO, hydrocarbon and odor control; gas compression and recycling; NO_x control and hydrocarbon vapor control. Each module is comprised of a number of nearly interchangeable processes with each individual process being applicable to a specific range of operating conditions. The control processes which are reviewed in this section in connection with each module are listed in Table 4-1. A discussion of the applicability of alternate processes to individual waste streams follows.

4.2.1 Coal Pretreatment and Handling

Several particulate control devices or techniques are potentially applicable to dusts generated as a result of coal crushing, screening and conveying. These include cyclones, fabric filters, venturi scrubbers, electrostatic precipitators, and dust supression systems. The key features of these controls, including their costs (where data were available) are presented in Table 4-2.

As indicated in Table 4-2, the control devices considered vary in their operating principle, effectiveness in removing particles in different size fractions, temperature applicability, particulate loading limitation and energy requirements. Cyclones are generally employed for the removal of bulk particulates (generally greater than 5μ in size) and, in many cases, upstream of


BOILERS
STEAM AND POWER GENERATION FLUE GASES
64*
PARTICULATE CONTROL
SO2 CONTROL AND/OR RECOVERY
CRUSHING/ SCREENING EMISSIONS
2
PARTICULATE CONTROL
BY-PRODUCT STORAGE VENT GASES
101
HC VAPOR CONTROL
PARTICULATE CONTROL
TRANSIENT GASES
102
CO, HC, & ODOR CONTROL (INCINERATION OR ADSORPTION)
CATALYST REGENERATION/DECOMMISSIONING OFFGASES
27
NOx CONTROL
SO2 CONTROL AND/OR RECOVERY
ATMOSPHERIC DISCHARGE
LOCK-HOPPER VENT GASES
6, 8
TO RAW PRODUCT GAS, LOCK-HOPPER, OR FUEL SUPPLY
DEPRESSURIZATION, AND STRIPPING ON GASES
69, 81
GAS COMPRESSION & RECYCLING
CO, HG & ODOR CONTROL (INCINERATION OR ADSORPTION)
CONCENTRATED ACID GASES
21, 22, 23
SULFUR RECOVERY
TAIL GAS TREATMENT FOR ADDITIONAL H2S OR SULFUR RECOVERY
HYDROCARBON REMOVAL/H2S CONCENTRATION
(RECYCLE H2S STREAM)

* NUMBERS REFER TO STREAMS IN FIGURES 2-2, 2-3, AND 2-4.

Figure 4-1. Process Modules for Air Pollution Control in a Commercial Lurgi SNG Facility

TABLE 4-1. AIR POLLUTION CONTROL PROCESSES REVIEWED FOR APPLICATION TO LURGI SYSTEMS FOR SNG PRODUCTION

Sulfur recovery	Claus, Stretford, Giammarco-Vetrocoke
Hydrocarbon removal/H_2S concentration	ADIP
Tail gas treatment for additional H_2S sulfur recovery	SCOT, Beavon, IFP-1, IFP-2, Sulfreen, Cleanair
SO_2 control and/or recovery	Wellman-Lord, Chiyoda Thoroughbred 101, Shell copper oxide, lime/limestone slurry scrubbing, double alkali, and magnesium oxide scrubbing
CO, hydrocarbon control	Thermal oxidation, catalytic oxidation, flares, activated carbon adsorption, vapor recovery, floating roof storage
Particulate control	Fabric filter, electrostatic precipitation, venturi scrubbing, cyclones, dust suppression with water sprays
Compression and recycling	Compression and recycling
NO_x control	Combustion modification and dry and wet processes

TABLE 4-2. KEY FEATURES OF PARTICULATE CONTROL DEVICES/TECHNOLOGY(58)

Control Device	Operating Principle	Efficiency Range, wt %	Particle Size Removal Range	Particulate Loading Limitation	Pressure Drop	Advantages	Disadvantages	Costs (First quarter, 1978 dollars)
Cyclone	Removal of particulates from a gas by imparting a centrifugal force to the gas stream. The inertia of the particulates carries them to the cylindrical walls where they fall to the bottom of the cyclone for removal.	50 to 80% for 5 µm 80 to 95% for 5 to to 20 µm	>5 µm	>2.4 g/m³ (>1 gr/ft³)	1.3-10.2 cm (0.5 to 0.4 in.) W.G.	High reliability due to a simple collection system. Low energy requirements.	Cannot efficiently remove particulates below 5 µm.	Costs vary considerably depending on the cyclone size, nature of particulates, loading, removal efficiency, material of construction and cyclone designs; cyclones are generally less expensive than most other particulate control methods.
Fabric Filter (Baghouse)	Removal of particulates from a gas stream by impaction or interception on a fabric filter (generally tubular shape). Particulates can be removed from filter media by mechanical shaking or a pressurized reverse air flow.	98.5 to 99.5% for 0.25 to 0.5 µm 99.0 to 99.5% for 0.75 to 1.0 µm 99.9% for 100 µm	>0.2 µm	>0.24 g/m³ (>0.1 gr/ft³)	5.1-25 cm (2 to 10 in.) W.G.	High particulate collection efficiency.	High capital and operating costs. Plugging problems will result if feed stream is saturated or wet or contains tarry/oily materials. Temperature limit varies with type of filter media utilized. Generally limited to 560°K (550°F) maximum temperature.	Capital $69-109/m³/min. of installed capacity ($1.95-3.10/acfm) Operating $18-24/m³/min. ($0.50-0.67/acfm)
Venturi Scrubber	Removal of particulates from a gas stream by impingement with atomized scrubbent droplets. The agglomerated particles are subsequently removed in a centrifugal collector.	60 to 92.5% for 0.25 µm 85 to 97.2% for 0.5 µm 92 to 99% for 0.75 µm 95 to 99.6% for 1.0 µm	>0.5 µm	>0.24 g/m³ (>0.1 gr/ft³)	25-250 cm (10 to 100 in.) W.G.	High particulate collection efficiency capable of treating streams with wide temperature, pressure and gas composition ranges.	Liquid scrubbing wastes are produced which may require treatment. High efficiencies require high energy consumption. Some potentially valuable dry material cannot be directly recovered.	Capital $99-212/m³/min. of installed capacity ($2.80-6.00/acfm) Operating $503-512/m³/min. ($14.25-14.50/acfm)
Electrostatic Precipitator	Removal of particulates from a gas stream by imposing an electrical charge and collecting the charged particles on oppositely charged collector plates. Collected solids are normally removed by mechanical rapping with hammers or vibrators.	90 to 99.4% for 0.1 µm 90 to 98.7% for 0.5 µm 95 to 99.5% for 1.0 µm 98 to 99.9% for 5.0 µm	>0.1 µm	>0.24 g/m³ (>0.1 gr/ft³)	0.51-2.5 cm (0.2 to 1 in.) W.G.	Suitable for high temperature applications. Low pressure drop, can treat large volumes of gas. Highly efficient for small particulates.	High capital costs. Generally applied at pressures near atmospheric. Collected particulates must have a suitable electrical resistivity to facilitate efficient collection. Not applicable to explosive gases.	Capital $185-468/m³/min. of installed capacity ($5.25-13.25/acfm) Operating $23-92/m³/min. ($0.65-2.60/acfm)
Dust Suppression System	Control of fugitive dust generated by material transfer and handling by utilizing high pressure nozzles spraying water containing wetting agent.	Without additive: 80% for 5 µm 43% for 3 µm 25% for 1 µm Without additive but with steam addition: 43% for 3 µm 40% for 1 µm With wetting agent: 95% of overall mass	>1 µm	No specific limitations	Not applicable	No waste disposal problem, simple system design and maintenance. Low capital and operating costs.	Clogging can occur if spray nozzle flow rate is too high. Low efficiency for small particles. Freezing can occur if adequate heat tracing is not used.	No generalized cost data available

other control devices. The capital and operating costs for cyclones are relatively low. Baghouses have very high particulate removal efficiency, and can lend themselves to applications involving small or intermittent gas flows. Baghouses, however, have high pressure drops (e.g., in comparison with electrostatic precipitators), and cannot ordinarily handle wet gases, gases containing oily materials or gases having temperatures in excess of 560°K (550°F).

Venturi scrubbers can generally handle gases having temperatures higher than that which can be handled by fabric filters, can operate at high pressures, can tolerate wet and tarry gases, and can be very efficient for the removal of submicron particles. In contrast to other devices in which the particles are collected in dry form, venturi scrubbers generate a wet slurry which is more voluminous and generally more difficult to dispose of.

Electrostatic precipitators are high efficiency particulate removal devices, have low pressure drops, are capable of handling large volumes of gases and can tolerate high feed gas temperatures. Electrostatic precipitators, however, are not generally suitable for applications to gases above atmospheric pressure and are not economical for treating small or intermittent gas flows (such as those resulting from material handling dust collection systems).

A dust suppression system consists of a spray system using water containing wetting agents. The sprays are generally applied continuously to open conveyors, storage areas and transfer points. The function of the wetting agent is to reduce water surface tension and enhance particulate removal efficiencies. Dust suppression systems are simple to operate, do not create a waste disposal problem and have low capital and operating costs. An improperly designed and operated dust suppression system may result in clogging or packing of fine screens. Heat tracing may be required to prevent freezing of water in the piping system.

The quantity of a solid waste stream generated by dry particulate removal devices (cyclones, baghouses and electrostatic precipitators) is dependent upon the inlet particulate loading and the removal efficiency. Dry particulate control devices may be more desirable than wet control devices (e.g., venturi scrubber) for application to coal crushing and screening, especially when the collected coal dust is to be utilized for power production or sold.

In summary, a dust suppression system is most suitable for the control of particulates emitted from conveyors, transfer points and other material handling operations. Particulate emissions from crushing and screening would probably be best controlled by a dust collection system utilizing a baghouse.

4.2.2 Coal Gasification

Control of Lockhopper Offgases. Feed and ash lockhopper vent gases are the only routine gaseous waste streams from the gasification operation. As discussed in Sections 2.2 and 3.5, product gas (raw, cleaned or SNG) or inert byproduct gas (e.g., CO_2 from Rectisol process) can be used for feed lockhopper pressurization. When product gas is used, the lockhopper vent gas is mostly recycled to the process with only about 3% of it discharged as an off-gas. When CO_2 is used for lockhopper pressurization, the entire volume of the pressurization gas would be discharged as the off-gas. Because of the possible presence of contaminants, treatment of the off-gas may be necessary prior to atmospheric discharge.

The lockhopper off-gas may require particulate removal and possibly incineration to oxidize carbon monoxide, hydrocarbons, and hydrogen sulfide. Due to the relatively small volume and intermittent nature of the off-gas, fabric filters appear suitable for the treatment of the off-gas for particulate removal. The effect of tarry materials and moisture in the off-gas on the performance of the fabric filter remains to be evaluated.

The off-gas from the ash lockhopper would be composed mainly of steam with some entrained ash particulates. The volume of this stream is relatively small and its composition is not well defined to establish control requirements.

Control of Transient Waste Gases. Gas produced during start-up and shutdown and during upset conditions may not be suitable for conversion to SNG and hence would require disposal. Generally such gases would be incinerated in a flare. Flaring of waste gases is commonly practiced in refineries as a safety and emission control technique. The primary purpose of flaring is to convert organics, carbon monoxide, and reduced sulfur and nitrogen compounds to less hazardous forms (e.g., CO_2, SO_2, NO_x). Most flares in refinery service are elevated above ground level to provide for improved pollutant and heat dispersion. Steam (or other inert gas) is injected in the combustion zone of the flare to enhance turbulent mixing of waste gas and air and to suppress smoke formation. Since the quantity and composition of refinery waste gases vary widely over short periods of time, modern flares incorporate sensors and feedback controls to regulate air and steam feed rates in response to changing waste gas combustion characteristics.

Because of the highly variable nature of waste gases commonly flared, it is generally difficult to achieve the proper combustion conditions consistent with minimum emissions of oxidizable substances. Thus, even with sophisticated flare control systems, emissions of CO, unburned hydrocarbons, and odors are generally higher from flares than from other stationary combustion sources of a comparable heat rating. Although some noise is inherent in the release of steam through flare orifices, the venting of combustion products to the atmosphere, and the combustion process itself, such noise can be minimized by proper flare design (e.g., reducing the size of steam injection orifices) and operating conditions (e.g., using a minimum amount of smoke suppressant).

4.2.3 Gas Purification

In terms of total volume and content of H_2S and other reduced sulfur compounds, concentrated acid gas(es) from the Rectisol process is the most important gaseous waste stream in a Lurgi SNG facility. Two major approaches are possible for removal of most of the sulfur components before atmospheric discharge. These are sulfur recovery using wet or dry catalytic oxidation processes and incineration to convert reduced sulfur species to SO_2 followed by use of wet or dry SO_2 removal processes. Depending on the composition of the concentrated acid gas stream and the degree of control desired, the sulfur recovery approach may include pretreatment of the acid gas for H_2S concentration (and HC removal) and tail gas treatment for additional H_2S removal or sulfur recovery and/or HC/CO removal. Processes for sulfur recovery, pretreatment for H_2S concentration/HC removal, tail gas treatment, incineration followed by SO_2 removal, and HC/CO control are discussed below. The discussion includes identification of several options for the treatment of concentrated acid gases in an integrated Lurgi SNG plant.

Sulfur Recovery. Of a number of processes which are available for sulfur recovery, three are considered to be most promising for application to coal gasification. These three are Claus, Stretford and Giammarco-Vetrocoke (G-V), and have been widely used in natural gas, petroleum refinery and/or by-product coke industry. Table 4-3 summarizes the key features of these three processes.

TABLE 4-3. GENERAL CHARACTERISTICS OF SULFUR RECOVERY PROCESSES(58)

Process	Process Principle	Limits of Applicability	Control Efficiencies (%)						By-Product	Effect of CO_2	Commercial Applications
			H_2S	COS/CS_2	R-SH	HCN	NH_3	HC			
Claus	Catalytic oxidation of H_2S and SO_2 to elemental sulfur. Three operational modes of Claus plants have been commercially employed.*	Straight-through system utilized for higher H_2S concentrations. Split-stream system utilized for H_2S concentrations of 10-15%. Sulfur burning mode used for H_2S levels down to 5%.	90 - 95	90	95	Partially oxidized	Partially oxidized	90	Elemental liquid sulfur	Can adversely affect sulfur removal ability and therefore increase plant size. If CO_2 exceeds 30% and NH_3 exceeds 500 ppmv, catalyst plugging problems may occur.	Widely employed in petroleum natural gas, and by-product coke industry. One known application to gasification in South Africa.
Stretford	Liquid phase oxidation of H_2S to elemental sulfur in an alkaline solution of metavanadate and anthraquinone disulfonic acid (ADA) salts.	Present applications are generally for 1% sulfur or less.	99.9 or greater	0	0	-100 (converted to SCN^- in Stretford solution)	0	0	Elemental sulfur	High CO_2 concentrations will decrease absorption efficiency by lowering solution alkalinity. Increasing absorber tower height and base addition are required.	Primarily natural gas service, a few applications to petroleum refining and by-product coke industries. A unit has been constructed at the Lurgi gasification facility at Sasol, South Africa.
Giammarco-Vetrocoke (G-V)	Liquid phase oxidation of H_2S to elemental sulfur in potassium carbonate and arsenate/arsenite solution. A concentrated CO_2 stream with very low H_2S concentration is produced.	Maximum of 1.5% H_2S in feed stream.	99.99	Partially removed	Partially removed	?	0	0	Elemental sulfur which may require arsenic removal	Little or no effect. Process can be designed to selectively remove H_2S with low CO_2 absorption.	Primarily natural gas service, a few applications for hydrogen purification in petroleum refining and ammonia production.

*The three operational modes of the Claus process are: "straight-through," "split-stream" and "sulfur-burning." In the "straight-through" mode, all of the feed gas along with stoichiometric quantity of air to oxidize one third of the H_2S is fed to the catalytic reactor. In the "split flow" mode, one third of the gas feed is reacted with air, followed by recombination with the other two thirds of the gas feed prior to entering the reactor. In the "sulfur-burning" mode, elemental sulfur and air are injected into the combustion chamber to provide the SO_2 needed for the Claus and reaction.

Operating and cost data for the Stretford and Claus processes are presented in Table 4-4.

As indicated in Table 4-3, the Claus process is generally applicable to feed streams containing a minimum of 10-15% H_2S, whereas the Stretford and G-V processes are applicable to feeds containing around 1% H_2S. (Some Claus plants have been designed and are operating on feeds containing as low as 5% H_2S. The Stretford process has also been used with feeds containing more than 10% H_2S. At these high concentration levels, however, the Stretford process is not economically competitive with the Claus process.) The treated gas from the Claus process generally contains several thousand ppm of sulfur compounds (primarily H_2S), whereas the treated gas from the Stretford and G-V contains only a few ppm of H_2S. The Claus process is a dry high temperature process in which H_2S is catalytically reacted with SO_2 (produced by air oxidation of the H_2S) to form elemental sulfur. The Stretford and G-V processes are liquid-phase oxidation systems using aqueous solutions of alkaline metavanadate/anthraquinone disulfonic acid and arsenite, respectively. While other reduced forms of sulfur (e.g., CS_2 and COS) are partially removed by the Claus and G-V processes, they are not removed by the Stretford process. Since the Claus process operates at a relatively high temperature, it is also capable of oxidizing some of the hydrocarbons.

Unlike natural gas and refinery acid gases which generally do not contain high levels of CO_2, acid gases from coal gasification usually contain 75 to 99% CO_2. In the Claus process, high CO_2 concentration levels in the feed gas (greater than 30%v) would not create a major operating problem unless the gas also contains more than 500 ppmv of ammonia (this situation can lead to ammonium sulfide deposition in catalyst beds). High CO_2 levels, however, increase the total sulfur content of the Claus tail gas by the following reactions which occur over the Claus catalyst:

$$CO_2 + H_2S = COS + H_2O \quad \text{and} \quad CO_2 + 2H_2S = CS_2 + 2H_2O$$

In the Stretford process, high levels of CO_2 in the feed gas decrease the alkalinity of the sorbent and, hence, reduce the system efficiency. Thus, where high CO_2 levels are encountered, larger absorption towers would be required to obtain high H_2S removal efficiency. In the G-V process, CO_2 is partially removed by the sorbent, but the absorption of CO_2 does not significantly impair the H_2S removal efficiency.

Based on the data in Table 4-4, total annualized costs for Stretford and Claus plants designed for Lurgi acid gas service are about \$233 and \$107 per tonne of sulfur, respectively. These costs, however, are not directly comparable since the cost for the Stretford process is based upon 2% H_2S in the feed while that for the Claus process assumes over 15% H_2S in the feed. No cost data are currently available for the G-V process.

The Stretford process produces two waste streams (excluding the tail gas): solvent blowdown and oxidizer vent gas. Solvent blowdown is necessary to avoid buildup of the side reaction products in the Stretford solvent. These side reactions include the following(22):

$$2NaHS + 2O_2 = Na_2S_2O_3 + H_2O$$
$$4S + 6NaOH = Na_2S_2O_3 + 2Na_2S + 3H_2O$$
$$2HCN + Na_2CO_3 + 2S = 2NaSCN + CO_2 + H_2O$$

The estimated composition of the blowdown for a Stretford unit featured in the proposed design of the El Paso Lurgi facility is as follows(61): 80% H_2O, 10.8% $Na_2S_2O_3$, 4.4% NaSCN, 0.7% $NaVO_3$, 1.1% ADA and 3% $NaHCO_3$ and Na_2CO_3.

The oxidizer vent gas from the Stretford process is expected to consist mostly of air and water vapor; some sulfur compounds may also be present in this gas. No actual data are available for this stream.

The Claus process produces spent catalyst and in some cases, sour condensate as waste streams. The Claus catalyst has an estimated life of more than two to three years(62). The Claus process may generate sour condensates, depending on the moisture content of the feed. Any such waste would usually be returned to the sour water stripping units.

Hydrocarbon Removal/H_2S Concentration for Claus Plant Feed. The acid gases from the Rectisol process do not contain a sufficiently high concentration of H_2S to be suitable for direct feeding to the Claus process. Furthermore, these acid gases contain a relatively high concentration of hydrocarbons which would make temperature control difficult in the Claus reactor and can lead to catalyst deactivation via carbon formation on the catalyst surface. One approach to minimize catalyst deactivation and to obtain a concentrated H_2S Claus feed is selective removal of H_2S using an alkanolamine process such as the Shell ADIP process. The ADIP solvent (diisopropanolamine) does not absorb hydrocarbons and under

TABLE 4-4. OPERATING AND COST DATA FOR CLAUS AND STRETFORD PROCESSES

Parameters	Stretford (22,1)	Claus (22,60)
Absorbent reactor temperature	Ambient to 322°K (120°F)	311°K (100°F)
Pressure	Ambient to 7.0 MPa (1000 psia)	Near atmospheric
Loading	2% H_2S	15% H_2S
Regeneration Temperature	Ambient	--
Pressure	Atmospheric	--
Efficiency	To less than 1 ppmv H_2S	95-97% total sulfur removal
Chemical requirement, kg/10^6Nm^3 (lbs/10^6scf)	ADA:* 84(5) Sodium vanadate: 1.0 (0.06) Citric acid: 168 (10)	--
Steam requirement	830 kg/tonne sulfur	High pressure steam-437 kg consumed/tonne sulfur. Low pressure steam-4910 kg produced/tonne sulfur.
Electricity	1353 kwh/tonne sulfur	63 kwh/tonne sulfur
Capital costs†	$65,350/tonne/day sulfur capacity	$31,920/tonne/day sulfur capacity
Operating costs†	$55.50/tonne sulfur	$19.30/tonne sulfur

*Anthraquinone disulfonic acid

†All costs are adjusted to 1st quarter 1978 dollars; costs are for plant sizes similar to those which would be used in commercial Lurgi SNG facilities (60-200 tonnes sulfur/day)

proper operating conditions shows selectivity for H_2S over CO_2. Thus, the use of ADIP or a similar process to treat Rectisol acid gases can result in a hydrocarbon free, concentrated H_2S feed for Claus processing and a product gas which contains sufficient organics to be used as a plant fuel. Table 4-5 presents operating parameters and cost data for the ADIP process.

Tail Gas Treatment for Additional H_2S Removal or Sulfur Recovery. Depending on the characteristics of the concentrated acid gas and the specific sulfur recovery process employed, the treated gas from a sulfur recovery process may require additional treatment for sulfur (and hydrocarbons) removal before discharge to the atmosphere. As with most of the sulfur recovery processes, the tail gas removal processes have not been used in connection with coal gasification, but many of them have been used in other industries (primarily in the petroleum refining industry).

Table 4-6 summarizes the key features of the sulfur recovery tail gas treatment processes. The processes listed in this table fall into three general categories: (1) processes such as IFP-1 and Sulfreen which are essentially extensions of the Claus process; (2) processes such as Beavon, CleanAir and SCOT which catalytically reduce the more oxidized sulfur compounds (e.g., SO_2, CS_2, and COS) to hydrogen sulfide which is recycled to the sulfur recovery systems; and (3) processes such as Chiyoda Thoroughbred 101, Wellman-Lord, IFP-2 and Shell CuO which involve the removal of SO_2 by scrubbing and require feed incineration to convert all sulfur compounds to SO_2.

The processes in the first category have been employed exclusively for Claus plant tail gas treatment and are capable of reducing the sulfur level to less than 500 ppmv. As with the Claus process, these processes can tolerate high concentrations of CO_2 in the feed gas. In the Beavon and SCOT processes, hydrogen or synthesis gas is used for the reduction of oxidized sulfur; the reduction is carried out over a cobalt molybdate catalyst. In existing commercial applications, the product hydrogen sulfide in the tail gas from the Beavon and SCOT processes is treated for H_2S removal/sulfur recovery by the Stretford and alkanolamine processes, respectively. Total sulfur levels of less than 100 ppmv have been achieved by the application of Beavon-Stretford and SCOT-alkanolamine systems. In contrast to the first category of processes (processes which extend the Claus reaction), Beavon-Stretford and the SCOT-alkanolamine

TABLE 4-5. OPERATING PARAMETERS AND COSTS FOR THE ADIP PROCESS(22,58)

Contractor	
Temperature, °K (°F)	310 - 333 (100 - 140)
Pressure, MPa (psia)	0.1 - 7.0 (15 - 1015)
Loading	0.6 mole H_2S/mole amine
Stripper	
Temperature, °K (°F)	374 - 408 (250 - 275)
Pressure	Atmospheric
Efficiency	To less than 100 ppmv of H_2S
Raw Material Requirements	
ADIP solvent	2-5 x 10^{-4} kg/kg of H_2S removed
Utility Requirements	
Steam	4600 kg/tonne H_2S removed
Electricity	13.7 kwh/tonne H_2S removed
Capital Costs	$23,600*/tonne H_2S removed
Operating Costs	$17.33*/tonne H_2S removed

*These costs are in 1978 dollars and reflect units which process 10% H_2S feed. ADIP removes around 99% of the H_2S and up to 90% of the CO_2 so that equipment size and cost are not strictly a function of H_2S removal alone. It is assumed here that the costs are proportional to H_2S loading.

TABLE 4-6. KEY FEATURES OF SULFUR RECOVERY TAIL GAS TREATMENT PROCESSES

Tail Gas Removal Process	Process Principle	Feed Stream Requirements/ Restrictions	Sorbents/ Solvents	Product	Utility Requirements	COS and CS_2 Removal	Efficiency	Effect of CO_2 in Feed Gas
Chiyoda Thoroughbred 101	Thermal oxidation of sulfur compounds to SO_2, followed by liquid absorption	Incinerated Claus tail gas; no specific requirement on $H_2S:SO_2$ ratio	2% (by wt.) sulfuric acid solution	Gypsum ($CaSO_4 \cdot H_2O$) 5 to 20% moisture content	Very high	Largely oxidized by incineration, not absorbed by solution	95% SO_2 or less than 300 ppmv	No effect
Beavon	Catalytic reduction of sulfur compounds to H_2S, followed by Stretford process	Sulfur recovery process tail gas is heated upstream of catalytic reactor; no specific $H_2S:SO_2$ ratio required	Stretford process solution	Elemental sulfur	Low	Catalytically converted to H_2S	99.8% removal for Claus tail gas containing 4% equivalent H_2S	Reduces conversion efficiency by catalyst; decreases H_2S absorption by Stretford solution
CleanAir	Catalytic reduction of sulfur compounds to H_2S, followed by a continuation of the Claus reaction and Stretford process	$H_2S:SO_2$ ratio can vary up to 8:1 without affecting efficiency; designed specifically for Claus tail gas	Unknown aqueous solution and Stretford process solution	Elemental sulfur	Very low	Catalytically converted to H_2S	Plant effluent normally guaranteed to contain less than 250 to 300 ppm SO_2 equivalent	Reduces conversion efficiency of catalyst; decreases H_2S absorption by Stretford solution
IFP-1	Liquid phase continuation of Claus reaction at a low temperature	$H_2S:SO_2$ ratio maintained in the range of 2.0 to 2.4	Polyalkaline glycol	Elemental liquid sulfur	Very low	Not removed in catalytic reactor	Capable of reducing sulfur species in Claus tail gas to 2000 ppm as SO_2	No effect
IFP-2	Incineration of tail gas followed by ammonia scrubbing. Solution is evaporated to produce a concentrated SO_2 stream which is returned to the Claus plant.	$H_2S:SO_2$ ratio maintained in the range of 2.0 to 2.4	Aqueous ammonia solution	Elemental liquid sulfur	High	Oxidized by incineration, not removed in catalytic reactor	Capable of reducing sulfur species in Claus tail gas to less than 500 ppm	No effect

(CONTINUED)

TABLE 4-6. CONTINUED

Tail Gas Removal Process	Process Principle	Feed Stream Requirements/ Restrictions	Sorbents/ Solvents	Product	Utility Requirements	COS and CS_2 Removal	Efficiency	Effect of CO_2 in Feed Gas
Sulfreen	Solid phase continuation of Claus reaction at a low temperature	Optimum performance requires H_2S:SO_2 ratio of 2:1	None; sulfur vapor condensation process utilized	Elemental liquid sulfur	Very low	Not appreciably removed	Capable of removing 30 to 35% of sulfur in the tail gas	No effect
Shell Copper Oxide	Thermal oxidation of sulfur compounds to SO_2, followed by adsorption by CuO; a concentrated SO_2 stream is produced by desorption with a reducing gas (H_2)	Incinerated Claus tail gas; no specific requirement on H_2S:SO_2 ratio	Copper oxide	Concentrated SO_2 stream	No data available	Oxidized by incineration	90% SO_2 removal	?
Wellman-Lord	Thermal oxidation of sulfur compounds to SO_2, followed by liquid absorption; concentrated SO_2 is produced and recycled to Claus plant	Incinerated Claus tail gas; process can handle SO_2 concentrations well over 10,000 ppm	Concentrated sodium sulfite, bisulfite solution	Concentrated SO_2 stream (up to 90% SO_2 content)	High	Oxidized by incineration, not removed by process	Can remove in excess of 95% of SO_2	No effect
SCOT	Sulfur species are catalytically reduced to H_2S; H_2S is scrubbed in a regenerable amine system	Applicable to Claus tail gas	Alkanolamine solution	Concentrated H_2S stream	Moderate	Catalytically reduced to H_2S	Can remove 97% of sulfur species	Reduces conversion efficiency by catalyst; high CO_2 levels reduce efficiency of alkanolamine system

systems are adversely affected by high levels of CO_2 in the feed gas. The CO_2 in the feed gas reduces the efficiency of the catalytic reduction of COS and CS_2 to H_2S* and impairs the effectiveness of the Stretford and alkanolamine absorption systems. Table 4-7 presents operational parameters and cost data for the Beavon and SCOT processes.

The third category of processes which involve incineration followed by SO_2 recovery have been applied to Claus plant tail gas and to utility boiler flue gases. These processes, which are discussed in more detail below in connection with the incineration of acid gases, are capable of removing over 90% of the total sulfur in the feed gas. The Chiyoda Thoroughbred 101 and the Shell-CuO processes which employ sulfuric acid and CuO as sorbents, respectively, are not affected by high levels of CO_2 in the feed gas. In the Wellman-Lord process, the sorbent is an alkaline solution of sodium sulfite/bisulfite whose capacity for SO_2 absorption may be affected by very high levels of CO_2 in the feed gas. (The use of Wellman-Lord process for SO_2 removal has been successfully demonstrated on Claus plant tail gases containing over 50% v CO_2.) Table 4-8 presents operating and cost data for the Chiyoda and Wellman-Lord processes.

Incineration of Acid Gases Followed by SO_2 Removal. The major alternative to direct elemental sulfur recovery for treating concentrated acid gases from the Rectisol process is incineration of the gas to convert H_2S, COS, CS_2, and organic sulfur compounds to SO_2 followed by SO_2 removal. A number of processes including Wellman-Lord, Chiyoda Thoroughbred 101, lime/limestone scrubbing and Dual Alkali would be potentially applicable to SO_2 removal from incinerated acid gases. Although a number of the processes are under development for SO_2 removal, the above four processes which are considered here represent the state-of-the-art commercial FGD systems from the standpoint of performance and cost. Key features of these processes are presented in Table 4-9.

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*A typical Claus plant tail gas in Lurgi SNG service would contain about 64% CO_2, 12% H_2O and 1.1% total sulfur(31). For this gas composition and under equilibrium conditions (catalyst operating temperature of 670°K or 750°F and pressure of 0.1 MPa or 1 atmosphere), the effluent gas from the Beavon process should contain about 280 ppmv of COS. Union Oil Co., the vendor-licensor of the Beavon process, however, intends to offer a 250 ppmv total sulfur performance guarantee for the process in coal gasification applications(22).

TABLE 4-7. OPERATING PARAMETERS AND COSTS FOR BEAVON AND SCOT TAIL GAS TREATMENT PROCESSES*

	Beavon(58,63)	SCOT(58,64)
Operating Parameters		
Reactor		
Temperature °K (°F)	644 (700)	400 - 430 (260 - 320)
Pressure MPa (atm)	0.1 (1)	0.13 (19)
Condenser (absorber SCOT)		
Temperature °K (°F)	210 (100)	310 - 320 (100 - 120)
Pressure MPa (atm)	0.1 (1)	0.1 (1) atm
Efficiency	to less than 250 ppmv	to less than 250 ppmv
Raw Material Requirements		
Fuel Gas	37,000 Nm^3/day (1.25 Mscf/d) per tonne sulfur removed in Claus	--
Stretford solution	0.013 to 0.06 ℓ/sec (0.21-1.0 gpm) per 100 tonne/day S plant	--
Utility Requirements		
Steam	--	25.6 lb/tonne S removed in Claus
Electricity	68 kwh/tonne S in tail gas	1.4 kwh/tonne S removed in Claus
Cooling water	1400 ℓ/min for 100 tonne/day Claus	52 ℓ/min/tonne S removed in Claus
Fuel gas	see above	28 MMBTU/tonne S removed in Claus
Capital Costs	$28,280/tonne S removed in Claus	$35,000/tonne S removed in Claus
Operating Costs	$57.70/tonne S in Beavon tail gas	$10.00/tonne S removed in Claus

*All costs are adjusted to 1st quarter 1978 dollars. Costs presented are for units operating on 100 tonne sulfur/day Claus plants.

TABLE 4-8. OPERATING PARAMETERS AND COSTS FOR THE WELLMAN-LORD AND CHIYODA THOROUGHBRED 101 PROCESSES

	Wellman-Lord(51,58,60)	Chiyoda Thoroughbred 101(58,60)
Operating Parameters		
Absorption		
Temperature, °K (°F)	310 - 340 (100 - 150)	322 (120)
Pressure, MPa (atm)	0.10 (1)	0.1 (1)
Loading (ppm)	to 10,000 ppm	to 11,000 ppm
Regeneration		
Temperature, °K (°F)	369 (205)	--
Pressure, MPa (atm)	0.068 (0.7)	--
Efficiency, %	>90%	>90%
Raw Material Requirements	0.25 kg NaOH/kg S, 0.33 kg Na_2CO_3/kg S	1.38 kg calcium salt/kg S
Utility Requirements		
Steam	18,700 kg/tonne sulfur	593 kg/tonne sulfur
Electricity	1120 kwh/tonne sulfur	102 kwh/tonne sulfur
Process Water	0.055 ℓ/Nm^3 (0.0004 gal/scf)	--
Cooling Water	1.1 ℓ/Nm^3 (0.008 gal/scf)	0.825 ℓ/Nm^3 (0.006 gal/scf)
Costs*		
Capital	\$800 Nm^3/min.(\$21,400/Mscfm) capacity	\$554/Nm^3/min. (\$14,900/Mscfm) capacity
Operating & Maintenance	0.240 mils/Nm^3 (6.5 mils/Mscf)	0.32 mils/Nm^3 (8.5 mils/Mscf)

*Costs are adjusted to 1st quarter 1978 dollars. These cost estimates are based on sulfur plant sizes likely to be encountered in commercial SNG application (60-200 tonne sulfur/day). Although the data are for utility FGD service, costs for sulfur plant tail gas treatment are similar when compared on a "tonne of sulfur removed" basis(64).

TABLE 4-9. KEY FEATURES OF FOUR SO_2 REMOVAL PROCESSES(58)

Process Feature	Lime/Limestone Slurry Scrubbing	Dual Alkali Scrubbing	Chiyoda Thoroughbred 101	Wellman-Lord
Principle	Liquid phase absorption of SO_2 in a lime or limestone slurry.	Liquid phase absorption of SO_2 in a sodium hydroxide, sodium sulfite, sodium sulfate and sodium carbonate solution. A dilute mode process is used for SO_2 concentrations of 250 to 1500 ppm and a concentrated mode is used for SO_2 concentrations of 1800 to 8000 ppm and where less than 25% oxidation of collected SO_2 is encountered.	Thermal oxidation of sulfur compounds to SO_2, followed by liquid absorption.	Thermal oxidation of sulfur compounds to SO_2, followed by liquid absorption; concentrated SO_2 produced may be sent to a Claus or sulfuric acid plant.
Feed Stream Requirements	Particulates must be primarily removed in a venturi scrubber.	O_2 must be less than 7% for concentrated mode. Excessive particulates must be removed in a venturi scrubber.	Particulates must be primarily removed from feed.	Particulates must be primarily removed from feed.
Absorbent	6 to 12% lime or limestone slurry.	Sodium hydroxide, sodium sulfite, sodium sulfate and small amount of sodium carbonate.	2% (by wt.) sulfuric acid solution.	Concentrated sodium sulfite, bisulfite solution.
Product	Calcium sulfite and calcium sulfate.	Primarily calcium sulfite and calcium sulfate.	Gypsum ($CaSO_4 \cdot 2H_2O$) 50 to 20% moisture content.	Concentrated SO_2 stream (up to 90% SO_2 content).
Efficiency	Generally 70 to 90% for utility firing of high sulfur coal. 95-99% can be obtained. Removal efficiency will vary according to scrubber type and gas pressure drop. Over 99% removal efficiency can be achieved.	Capable of over 99% removal for typical coal fired utility flue gas and a concentrated mode process. A General Motors demonstrated (dilute mode) and an FMC pilot plant (concentrated mode) operate at approximately 90% SO_2 removal.	95% SO_2 or less than 300 ppmv.	Can remove in excess of 95% of SO_2.
Advantages	Low capital and O&M costs. SO_2 and particulates are removed. Fairly simple process. Conventional process equipment.	Low capital and O&M costs. SO_2 and particulates are removed. Conventional process equipment.	Produces potentially saleable gypsum byproduct; process commercially demonstrated.	Commercially demonstrated, lower potential for fouling/scaling than calcium-based processes.
Disadvantages	On line reliability may be low (70 to 85%) produces ~2 times (by wt.) as much waste sludges as collected ash. For low sulfur coals, SO_2 removal efficiency should be as low as 50%.	Produces ~1.5 times (by wt.) as much calcium sulfite/sulfate waste sludge as collected ash. Corrosion and pitting problems may require specific materials of construction.	High utility requirements; sulfuric acid absorbent requires that special metals be used in construction.	High utility requirements; special metallurgy, requires separate system to process concentrated SO_2 to sulfur or sulfuric acid.

The Wellman-Lord and Chiyoda processes are wet scrubbing systems which feature by-product recovery. In the Wellman-Lord process, SO_2 is absorbed in a concentrated sodium sulfite/bisulfite solution with subsequent regeneration by thermal processing. A concentrated SO_2 offgas stream is produced and the regenerated sulfite liquor is returned to the absorber after caustic addition. The Chiyoda process utilizes a dilute sulfuric acid solution containing iron catalyst to absorb/oxidize SO_2. The SO_2-rich solution is treated with limestone in a crystallizer to form gypsum crystals which are then separated and dried. The liquor is recycled to the absorber. Both of these processes have been applied to fuel combustion flue gases and to Claus plant tail gases and reportedly have achieved SO_2 levels of below 200 ppmv in the treated gases.

The lime/limestone slurry and Dual Alkali scrubbing processes have been developed and utilized for the removal of SO_2 from utility and industrial boiler flue gases. In the lime/limestone process the flue gas is scrubbed with a lime or limestone slurry (6-12%) to remove the SO_2. The initial scrubbing is carried out in a venturi scrubber which also removes most of the residual particulate matter. The bulk of the SO_2 removal is accomplished downstream in an absorption tower. The resulting spent calcium sulfite/sulfate sludge is discharged to a thickener/settling pond with the clarified liquid returned to the process. Being a "throw-away" process, the process generates a relatively large volume of sludge which requires processing and disposal. On a weight basis, the wet sludge produced would typically be twice the amount of fly ash and bottom ash produced in a coal-burning power plant(66). SO_2 removal efficiencies of up to 99% have been obtained in applications to flue gases from the combustion of high sulfur coals. Somewhat lower efficiencies have been reported for applications to lower sulfur fuels.

A concentrated sodium sulfite scrubbing solution is employed in the Dual Alkali process. The reaction of SO_2 with sodium sulfite produces sodium bisulfite which is reacted with lime in a separate vessel to regenerate sodium sulfite and precipitate calcium sulfite. The calcium sulfite sludge is concentrated by filtration prior to disposal. The dual alkali process can achieve 99% SO_2 removal efficiency when treating relatively concentrated SO_2 streams (1800-8000 ppmv) and 90% SO_2 removal when treating more dilute SO_2 streams (250-1500 ppmv). As with the lime/limestone slurry process, the Dual Alkali process generates large amounts of waste $CaSO_3/CaSO_4$ sludge (typically about 1.5 times as much as the amount of ash generated in a typical coal-fired utility boiler(66)).

Applications of lime/limestone and Dual Alkali processes to date have been to flue gases which contain around 1000-2000 ppmv SO_2 and 10% CO_2. Incinerated acid gas would generally contain considerably higher levels of SO_2 and CO_2 (at least 10,000 ppmv SO_2 and 50-70% CO_2). The expected performance of these processes with such feed is not known. The Wellman-Lord and Chiyoda processes, however, have been used for Claus tail gas desulfurization where the feed would be similar to those expected for incinerated acid gases in terms of SO_2 and CO_2 concentrations. When the Wellman-Lord process is employed, a system would be required to process the concentrated SO_2 stream from regeneration. The SO_2 may be converted to elemental sulfur in a Claus plant or pcoesessed to produce sulfuric acid.

The operating and cost data for the application of the Wellman-Lord and Chiyoda processes to Claus plant tail gas treatment were presented in Table 4-8. Table 4-10 presents cost data for the application of lime/limestone, Dual Alkali and Wellman-Lord processes to the desulfurization of flue gases from coal-fired boilers. Based on the data in Table 4-8 and the results of other studies(68), the Dual Alkali process would be economically most favorable for FGD applications. However, the Dual Alkali process has not been applied to the treatment of incinerated acid gases in a Lurgi facility or to other gases having similar compositions (e.g., Claus plant tail gas).

Hydrocarbon and Carbon Monoxide Control. Concentrated acid gases for the Rectisol process contain hydrocarbons and carbon monoxide and small amounts of methanol. Depending upon the approach used to control sulfur emissions, additional control for hydrocarbons and CO may be required. When the Claus process is used, with or without preconcentration of H_2S (e.g., using the ADIP process), organic compounds and CO are largely burned in the Claus furnace (or in plant boiler) and thus no further control would ordinarily be necessary. If Rectisol acid gases were treated by incineration followed by SO_2 removal, additional hydrocarbon and CO control would not be required. When Rectisol offgas is directly incinerated, the incineration may be accomplished in the plant boilers equipped with FGD systems, thereby allowing sulfur, HC and CO control from both acid gases and combustion flue gases in a single system.

TABLE 4-10. ESTIMATED COSTS FOR LIME/LIMESTONE, DUAL ALKALI AND WELLMAN-LORD FGD PROCESSES*

Process	Capital Cost ($/kw)			Operating Costs (mils/kwh)		
	200 MW	500 MW	1000 MW	200 MW	500 MW	1000 MW
Lime (69)	80	61	45	4.5†	3.6†	2.9†
Limestone (69)	88	68	51	4.2†	3.4†	2.7†
Dual Alkali (70)	65-75	--	--	2.8-3.3	--	--
Wellman-Lord (71)	--	70‡	60‡	--	2.6‡	2.1‡

*Mid-1977 basis

†An additional 15-20% would be required to account for sludge fixation

‡End product assumed to be sulfuric acid

When the Stretford process is employed for removal of H_2S from relatively dilute acid gases, the process tail gas will contain essentially all of the HC and CO originally present in the feed. Tail gas treatment processes such as Beavon and SCOT which would be used with the Stretford process will not result in HC and CO removal. Incineration of the tail gas which is required when Wellman-Lord or Chiyoda Thoroughbred 101 processes are used for tail gas treatment will, however, effect destruction of HC and CO. When either no tail gas treatment is employed or when Beavon or SCOT processes are used for the treatment of Stretford tail gas, HC and/or CO control can be accomplished prior to or after Stretford or Stretford/tail gas treatment processes, using any of the several processes listed in Table 4-11. Except for the incineration processes (the first three processes), the processes listed in Table 4-11 can be used either before or after sulfur recovery. The alkanolamine, carbonate scrubbing and cold water scrubbing separate HC and CO from the H_2S and CO_2 contained in the feed gas. The separated HC/CO stream is subsequently incinerated or used as plant fuel. The cuprous ammonium solution absorption and cryogenic separation processes remove only CO and HC, respectively. As indicated by the cost data in Table 4-11, the incineration options are generally more cost effective than absorption/scrubbing options. In all cases, the recovery of fuel value will partially (or totally) offset the energy used by the process.

TABLE 4-11. CAPITAL AND OPERATING COSTS FOR SELECTED HC AND CO REMOVAL PROCESSES APPLIED TO A 7 x 10^6 NM^3/D (250 x 10^6-SCFD) LURGI SNG PLANT*(22,128)

Candidate	Estimated Capital Investment ($106)	Capital and Operating Costs ($$10^6$/year)†						Total Cost ¢/kcal (¢/10^6 Btu)
		Capital Charges	Fuel‡	Steam§	Catalyst	Other	Total	
Incineration in coal-fired boiler	9	2.2	(0.2)#	0		1.7	3.7	16 (4)
Incineration in coal, gas-fired boiler	6	1.5	12.0	(5.0)		1.5	10.0	44 (11)
Catalytic oxidation	14	3.5	0	(1.8)	0.3	2.6	4.6	20 (5)
Alkanolamine (ADIP)	50††	--	--	--		--	--	**
Hot carbonate scrubbing	38	9.4	(8.0)	19		17.9	38.3	168 (42)
Cold water scrubbing	66	16.3	(8.0)	8		23.4	39.7	176 (44)
Cuprous ammonium solution absorption	20	4.0	(0.2)	2		7.9	14.6	64 (16)
Cryogenic separation	100	24.7	(8.0)	13		28.7	58.4	256 (64)

*Basis: 20-year discounted cash-flow method with 100% equity financing and 12% return on equity after taxes.

†Costs and production rate based on 365 days/year. Capital charges are based on an annual fixed charge rate of 24.7%.

‡Coal at \$0.30/10^6 Btu; medium-Btu gas (synthesis gas) at \$3.50/10^6 Btu; recycled (contaminated) fuel gas credited at \$3.00/10^6 Btu. Product SNG was estimated at \$4.00/10^6 Btu.

§Steam (900 psig, 825°F) is estimated at \$1.35/10^3 lb.

#Numbers in parentheses indicate credit.

**Insufficient data to permit cost estimation.

††Estimated based on data in Reference 22.

Options for the Control of Concentrated Acid Gases in an Integrated Lurgi SNG Plant. Table 4-12 lists 10 options for the control of acid gases in an integrated Lurgi SNG plant. The table includes some qualitative statements on the advantages and disadvantages of the options based upon the capability of the various control processes discussed above. Some options (e.g., incineration of concentrated acid gases and atmospheric discharge) would be technically unattractive and environmentally unacceptable for use in the U.S. The applicability of certain options (e.g., those using Claus or Stretford processes for sulfur recovery) is dependent on the sulfur concentration in the gas stream, which is in turn determined by the sulfur content of the feed coal and the specific design of the Rectisol acid gas treatment process employed. Accordingly, the selection of the best option for the management of a specific sulfur-bearing stream must be based on a case-by-case analysis. The determination of the best option for use in a specific facility is also complicated by a number of factors which relate primarily to the lack of data on (1) the detailed composition of gas streams from commercial facilities and (2) performance costs and environmental aspects of actual application of control processes to Lurgi gas streams. For example, the Stretford process has been demonstrated to be highly effective for H_2S removal from refinery and coke oven gases which contain low to moderate levels of CO_2; however, insufficient data exist for commercial applications to coal gasification acid gases which in some cases may contain 90% or more CO_2. A small Stretford unit is being tested at the Fort Lewis SRC pilot plant handling concentrated acid gas from a diethanol amine unit. Satisfactory performance has not been reported for this unit(72).

Some of the options listed in Table 4-12 have not appeared in the designs for proposed commercial SNG facilities. In some cases this may be due to the lack of engineering data for such options. For example, all proposed designs include Claus and/or Stretford processes for the recovery of H_2S from concentrated acid gases. Due to some of the shortcomings associated with these processes for handling gases containing high levels of CO_2, it is possible that acid gas incineration followed by SO_2 recovery (in a Wellman-Lord or wet limestone unit) alone or in conjunction with flue gas from utility boilers may be technically and economically superior.

TABLE 4-12. CONTROL OPTIONS FOR THE CONCENTRATED ACID GAS STREAM FROM THE GAS PURIFICATION OPERATION

Control Options	Comments
1. Claus plant sulfur recovery	1. Probably unacceptable because of high concentration of total sulfur in the tail gas; feed gas, H_2S enrichment and hydrocarbon removal would likely be required.
2. Claus plant sulfur recovery and tail gas incineration	2. Probably unacceptable because of high levels of SO_2 in the tail gas; only applicable to streams containing more than 5-15% H_2S.
3. Claus plant sulfur recovery and tail gas treatment	3. Tail gas treatment not highly effective when feed gases contain high levels of CO_2; only applicable to streams containing more than 5-15% H_2S.
4. Same as Option 1 plus SO_2 control and/or recovery	4. Reasonable option when feed gases contain more than 5-15% H_2S; total sulfur removal efficiency may be less than Option 5.
5. Stretford sulfur recovery	5. Inapplicable to waste gases containing high levels of H_2S; may not be economical for gases containing high CO_2 levels; discharge may contain high COS and HC levels.
6. Same as Option 5 plus tail gas treatment	6. Same as for Option 5.
7. Same as Option 6 plus incineration	7. Same as for Option 5 except for oxidation of CO and HC compounds.
8. Incineration	8. Unacceptable because of high SO_2 emissions.
9. Same as Option 8 plus SO_2 control and/or recovery	9. Many SO_2 recovery processes generate sludges requiring disposal; no by-product sulfur is recovered; regenerable SO_2 removal processes may be operated in conjunction with sulfur recovery units.
10. Incineration, treatment for control and/or recovery in combination with flue gases from utility boilers	10. Same as for Option 9; some economy of scale may be realized if flue gas desulfurization is required on utility boilers.

4.2.4 Gas Upgrading

The only gaseous waste stream generated in the gas upgrading operation is the flue gas from catalyst regeneration/decommissioning. This stream will be of a relatively small volume compared to other gaseous waste streams in a Lurgi plant and will only be generated intermittently (perhaps once every year or two). Based on current technology, incineration in the plant flare or utility boiler appears to be the most practical approach to the control of this stream; the effectiveness of incineration for the control of this stream is not known. If particulate control is required, a fabric filter system would likely be the best candidate. No specific control techniques for metal carbonyls which may be present in the gas are identified, although incineration would likely convert such substances to their metal oxide forms.

4.2.5 Auxiliary Processes

As discussed in Section 3.5.5, major gaseous waste streams associated with auxiliary processes in Lurgi systems are depressurization and stripping gases, by-product storage vent gases and steam and power generation flue gases. The following is a brief review of processes for the control of these three waste streams. As noted previously, steam and power generation flue gas and the concentrated acid gas are the two most important gaseous waste streams in a Lurgi SNG plant. Some of the most effective options for air pollution control in an integrated SNG facility include joint treatment of these streams. A brief discussion of the control options for integrated facilities is also included in this section.

Control of Depressurization and Stripping Gases. Depressurization gases from Lurgi tar/oil/gas liquor separation and overhead gases from sour water stripping contain H_2S, NH_3, HC and CO at concentrations which could constitute an emissions problem if such gases were vented directly to the atmosphere. In comparison to Rectisol acid gases, the volumes of these streams are small, however, and thus combining them with Rectisol gases which are sent to sulfur recovery would not dramatically affect the design of the sulfur plants. Alternatively, these gases could be incinerated in the plant flare or, if sulfur control is required, in the utility boiler followed by SO_2 removal.

Control of By-Product Storage Vent Gases. Some gasification by-products such as naphtha, light oil and phenols are sufficiently volatile to require control of evaporative emissions which occur during handling and storage. The control of such emissions is well established and is widely practiced in other industries, especially the petroleum industry. EPA has promulgated New Source Performance Standards (NSPS) for storage of petroleum liquids; these standards are expected to be applicable to gasification by-product storage. Generally, the control techniques applicable to a given liquid are determined by its vapor pressure. The more volatile liquids require vapor recovery systems while less volatile liquids require either floating roof storage or conservation vents.

A variety of vapor recovery systems exist and most are approximately 90% efficient. These systems include: liquid absorption (which utilizes a solvent with low vapor pressure to absorb vapors); vapor compression (which compresses collected vapor into the liquid state); vapor condensation (which utilizes a refrigerated brine to condense collected vapor); and adsorption (whereby the collected vapor is adsorbed on activated charcoal or silica gel).

Control of Flue Gases from Steam and Power Generation. Depending upon the fuel used for on-site steam and power generation at a Lurgi SNG facility, the combustion flue gases may require control of particulate, NO_x and sulfur emissions. Indeed, fuel combustion would generally represent the largest source of potential emissions of SO_x, NO_x and particulates in a Lurgi SNG plant. When coal and/or by-product tars/oils/phenols are utilized as fuel, particulate and SO_x control will likely be required in order to meet state and federal emission limitations. Federal NSPS for fossil fuel-fired steam generating plants have been promulgated and the control technology for meeting these standards is reasonably well established. Flue gas emissions at Lurgi SNG facilities are not expected to involve any major new problems for these established control techniques.

The major candidate particulate control techniques applicable to combustion flue gas from large boilers are electrostatic precipitators and fabric filters. The key features and costs of these types of processes have been presented in Table 4-2. Although not reflected in the cost data shown in Table 4-2, more recent data indicate that for large scale boiler application where high removal efficiency is desired, fabric filters would be more economical than electrostatic precipitators(73). In recent years the trend in the electric utility industry has been toward the use of fabric filters, mainly due to increasingly strict particulate control requirements. SO_x control in flue gases from coal and/or by-product combustion can be accomplished utilizing any of a number of FGD systems. Four such processes which have perhaps the best commercial prospects were discussed in Section 4.2.3. Of these processes, lime or limestone scrubbing appears to be the most commercially demonstrated process(es) and most electric utilities which are planning to install FGD systems have chosen this option to meet near term needs.

Onsite steam and power generation requirements may also be met using as fuel low to medium Btu gas produced by air blown gasifiers. In this case, particulate control is accomplished as part of the gas quenching/tar and oil separation and hence additional particulate control is not required for the combustion flue gases. Sulfur compounds (mainly H_2S) would be removed from the fuel gas using any of a number of commercially available acid gas removal processes. For H_2S removal from low/medium Btu gas, the most economic choices are either Selexol absorption with Claus sulfur recovery or Stretford absorption/sulfur recovery(74,2). One desirable feature of these processes is that they are selective for the removal of H_2S over CO_2. (For fuel use, removal of CO_2 is unnecessary or, in the case of turbine use, undesirable.) The Selexol process uses dimethyl ether of polyethylene glycol for physical absorption of acid gases and can achieve a high degree of selectivity for H_2S. The separated H_2S is concentrated enough for Claus processing. Tail gas treatment would ordinarily be required for the Claus plant. Unfortunately, Selexol solvent also removes naphtha from feed gases and hence a hydrocarbon removal step between the Selexol and the Claus unit is necessary to recover the fuel value of the absorbed hydrocarbons and to avoid problems in the Claus plant.

Stretford absorption/sulfur recovery was described in Section 4.2.3. For application to fuel gas, the required degree of total sulfur removal is not likely to be as stringent as in the case of concentrated acid gas treatment. The Stretford process has the advantages of achieving sulfur removal and recovery in a single process and of not removing hydrocarbons, CO and H_2 from the fuel gas.

The relative economics of coal/by-product use vs. fuel gas use for onsite steam and power generation are not well known at this time. At least one economic study has predicted that coal gasification/combined cycle systems for electricity generation (with Selexol sulfur removal from fuel gas) are cost competitive with conventional coal-fired boilers using state-of-the-art FGD processes(74). Generally, the fuel gas option will result in lower total emission of SO_x, particulates and NO_x.

The combustion flue gases will contain varying amounts of NO_x depending on the fuel type used (coal, fuel gas or gasification by-products) and combustion conditions. Control of NO_x emissions can be achieved through combustion modification and/or use of add-on processes. Combustion modification, which may include staged-combustion, use of low excess air, reduction of air preheating, steam and water injection and reduced heat release rate, may result in as much as 60% reduction in NO_x emissions from gas-fired boilers. Somewhat lower efficiencies are obtained when fuels containing nitrogen are used (e.g., coal and tar). Add-on processes generally fall into two categories: dry processes and wet processes. Most dry processes involve catalytic reduction of NO_x with ammonia which is added to the flue gas. Wet processes involve a combination of absorption and oxidation or reduction for NO_x removal. Removal efficiencies greater than 90% can be obtained with dry or wet processes. Only a few of the add-on NO_x control processes have been developed commercially. Applications of the few processes which have attained commercial status have been limited to facilities in Japan and to oil-fired utility and industrial boilers.

Control Options in Integrated Facilities and Associated Emissions, Costs and Energy Requirements. The overall effectiveness and economics of air pollution control in Lurgi SNG facilities cannot be properly assessed without an examination of integrated systems for management of gaseous waste streams. A number of factors influence the total emissions and air pollution control costs for an integrated Lurgi SNG facility. These include the coal sulfur content, the plant size, the design of the Rectisol acid gas removal unit, the fuel used for onsite steam and power generation, and the specific air pollution control processes employed. Table 4-13 summarizes the estimated total emissions for the five proposed commercial Lurgi SNG plants. As noted in the table, the

TABLE 4-13. SUMMARY OF ESTIMATED CONTROLLED EMISSIONS FOR PROPOSED COMMERCIAL LURGI SNG FACILITIES (IN KG/HR)

Proposed Project	Gasification Plant		Onsite Fuel Combustion	Facility Total	Factors Affecting Emissions
	Acid Gases*	Feed Lockhopper Vent Gas			
El Paso(2,22)					
SO_2+	116	6	41	163	Low sulfur/HHV ratio coal, high degree of H_2S removal in Stretford unit, desulfurized fuel gas used as plant fuel, Stretford off-gases not incinerated
NO_x	24	--	70	94	
NMHC	2523	17	--	2640	
Particulates	1	--	--	1	
CO	811	295	--	1106	
WESCO(3)					
SO_2	77	33	265	375	Low sulfur/HHV ratio coal, combination of Stretford and Claus sulfur recovery, tail gas treated with coal-fired boiler flue gases for SO_2 removal
NO_x	-- ‡	--	720	720	
NMHC	--	451	--	451	
Particulates	--	--	33	33	
CO	--	--	--	--	
ANG(15)					
SO_2	545	11	640	1196	Medium sulfur/HHV ratio coal, Stretford efficiency lower than that in the El Paso design, coal-fired boiler used with FGD
NO_x	-- ‡	--	500	500	
NMHC	--	--	45	--	
Particulates	--	--	77	77	
CO	--	--	164	--	
Wyoming(14)					
SO_2	164	26	1035	1125	Very low sulfur/HHV ratio coal, no FGD employed on coal-fired boilers, Stretford efficiency lower than that in the El Paso design
NO_x	310	--	1210	1520	
NMHC	--	--	--	--	
Particulates	--	--	140	140	
CO	--	--	--	--	
Dunn Co.(13)					
SO_2	460	12	860	1332	Same as for ANG design
NO_x	--	--	1300	1300	
NMHC	--	--	--	--	
Particulates	--	--	180	180	
CO	--	--	--	--	

*Includes sour water stripper overhead

+All sulfur emissions in this table are reported as SO_2 equivalent

‡Included in combustion emissions.

emissions vary widely reflecting differences in plant designs (including power/steam generation systems selected), control systems used and coal feed characteristics.

For analysis purposes a limited number of options are examined in this section based on certain assumptions as to the plant size, coal sulfur content, etc. As noted previously, concentrated acid gases from the Rectisol unit and flue gases from steam and power generation are the most important gaseous streams from the standpoint of control requirements in an integrated plant. Control of dust emissions from coal preparation has been discussed earlier. Relatively small volume waste streams such as transient waste gases and catalyst decommissioning offgases would be handled in plant flares. Sour water stripping and depressurization gases would generally be combined with bulk acid gas streams or incinerated. Lockhopper vent gases would be recovered to a major extent, with only a small volume of such gases being discharged to the atmosphere.

Five control options have been identified for the management of Rectisol acid gases and combustion flue gases in an integrated facility. Table 4-14 presents the key features of these options. These options cover the range of sulfur recovery/FGD systems which have been proposed for use in commercial Lurgi plants or which would be potentially suitable for such applications. Emissions associated with each option have been estimated based upon the flow diagrams and the engineering assumptions described in Appendix B. A summary of the estimated emissions is presented in Table 4-15. For the five options reviewed, the contribution of treated Rectisol acid gases to total plant SO_2 emissions ranges from around 10 to 90%, depending on whether sulfur recovery tail gas treatment is utilized and whether desulfurized fuel gas is used for steam and power generation. Option 4, in which all plant flue gases are treated in an FGD unit, has the highest total SO_2 emissions. Option 1, in which acid gases are treated in a Stretford unit and the off-gases from the Stretford unit and the combustion flue gases are handled in an FGD unit, achieves the lowest SO_2 emissions. Emissions of HC and CO associated with incinerated sulfur recovery tail gases constitute from 20 to 75% of the total plant HC and CO emissions. As would be expected, NO_x and particulate emissions are not greatly influenced by sulfur and HC/CO control alternatives employed.

The estimated costs for the five options are shown in Table 4-16. Within the accuracy of the cost estimates, the costs associated with Options 1, 3, 4

TABLE 4-14. FEATURES OF OPTIONS CONSIDERED FOR AIR POLLUTION CONTROL IN INTEGRATED LURGI SNG FACILITIES*(2,3,13,14,15)

Option No.	Key Features	Proposed Commercial Project(s) Whose Designs Have Similar Features	Comments
1	• Stretford unit handles combined acid gases from Rectisol. • Stretford offgases incinerated in superheater furnace followed by SO_2 removal in conjunction with coal-fired boiler flue gases. • On-site energy needs met by burning coal, tar, oil, naphtha and phenols.	ANG Wyoming	ANG design does not feature coal use for on-site energy needs. Power is purchased from off-site source. All gasification byproducts are burned rather than marketed. Wyoming design is similar to ANG except that coal rather than gasification byproducts are burned to supply plant energy needs.
2	• Stretford unit handles combined acid gases from Rectisol. • Stretford offgases incinerated in gas turbine generators. • On-site energy needs met by fuel gas which has been desulfurized in Stretford unit.	El Paso	In the El Paso design, all on-site energy needs are met by fuel gas. Byproducts are sold and not used for fuel on site. Stretford offgas is incinerated in a catalytic converter rather than in turbines.
3	• All Rectisol acid gases are sent to ADIP unit for concentrating H_2S and removing hydrocarbons. • Claus plant used for sulfur recovery followed by Beavon/Stretford tail gas treatment. • Coal supplies all energy needs on site and boiler flue gases are treated for SO_2 removal.	WESCO Dunn Co.	In WESCO and Dunn Co. designs, only the rich H_2S Rectisol stream is sent to ADIP/Claus/tail gas treatment. The lean H_2S stream is sent to Stretford. Thus, WESCO and Dunn Co. are a combination of Options 1 and 3.

TABLE 4-14. CONTINUED

Option No.	Key Features	Proposed Commercial Project(s) Whose Designs Have Similar Features	Comments
4	• All acid gases are directly routed to utility boiler for incineration. SO_2 is subsequently removed from flue gases.	No proposed commercial facility has this feature.	--
5	• Rectisol unit is designed to selectively recover about 30% of feed H_2S as a concentrated stream suitable for Claus processing. • Stretford handles lean H_2S stream from Rectisol. • Claus plant tail gas treatment handles rich H_2S stream from Rectisol. • Stretford tail gas is incinerated with supplemental fuel. • Steam and power are supplied by coal-fired boiler. Flue gases are treated for SO_2 removal.	WESCO Dunn Co.	Stretford offgases are incinerated in utility boiler in WESCO and Dunn Co. designs rather than separately as in Option 5.

*See Figures B-1 through B-5 in Appendix B for the flow diagram for the options.

TABLE 4-15. SUMMARY OF ESTIMATED EMISSIONS FOR AIR POLLUTION CONTROL OPTIONS (KG/HR)

Option No.	Pollutant	Contribution from Rectisol Acid Gases	Contribution from Fuels	Total
1	SO_2	25	150	170
	HC	30	40	70
	CO	100	140	240
	NO_x	300	900	1200
	Particulates	Negligible	60	60
2	SO_2	250	20	270
	HC	10	37	47
	CO	25	75	100
	NO_x	100	1400	1500
	Particulates	Negligible	Negligible	Negligible
3	SO_2	20	280	300
	HC	20	20	40
	CO	50	50	100
	NO_x	Negligible	1100	1100
	Particulates	Negligible	50	50
4	SO_2	1200	300	1500
	HC	2*	18	20
	CO	5	45	50
	NO_x	100	1000	1100
	Particulates	Negligible	50	50
5	SO_2	240	280	520
	HC	20	20	40
	CO	80	50	130
	NO_x	100	1100	1200
	Particulates	Negligible	50	50

*See **Appendix B** for flow diagrams, assumptions, and detailed calculations.

TABLE 4-16. ESTIMATED COSTS FOR AIR POLLUTION CONTROL OPTIONS (10^3 DOLLARS, 1978 BASIS)

	Option Number				
	1	2	3	4	5
Stretford					
Capital	9,681	11,745*	--	--	6,694
Annual operating	2,960	3,591*	--	--	2,057
Electrostatic Precipitator					
Capital	3,365	--	15,466	15,966	10,480
Annual operating	65	--	301	311	208
Wellman-Lord					
Capital	22,684	--	26,343	27,199	17,848
Annual operating	3,473	--	4,033	4,164	2,732
ADIP					
Capital	--	--	3,988	--	--
Annual operating	--	--	792	--	--
Claus					
Capital	--	--	4,475	--	1,288
Annual operating	--	--	974	--	273
Beavon					
Capital	--	--	3,964	--	1,220
Annual operating	--	--	154	--	35
Incineration					
Capital	5,300	5,300	0	5,300	14,000
Annual operating	1,700	1,500	0	1,700	1,100
Lurgi Fuel Gas Production					
Annualized total cost	--	11,054†	--	--	--
Total Capital	42,830	17,045	53,736	48,465	51,300
Annual Capital‡	7,709	3,068	9,672	8,723	9,234
Annual Operating	8,198	16,145	6,254	6,175	6,391
TOTAL ANNUAL COST	15,907	19,213	15,926	14,898	15,625

*Stretford units are used for both Rectisol acid gas treatment and for fuel gas treatment in Option 2. Although the fuel gas Stretford is designed for 100 ppmv H_2S and the Rectisol Stretford for 10 ppmv H_2S, costs on a "per tonne sulfur removed" basis are assumed to be the same for both units.

†The annualized cost of Lurgi fuel gas production is estimated from data in Reference 74. It is assumed that the gas fired boiler in Option 2 would cost the same as coal/byproduct fired boilers in other options and hence, boiler cost need not be included for comparison purposes.

‡Depreciation and interest = 0.14 x total installed cost. Taxes, insurance and administration = 0.04 x total installed cost.

and 5 may be considered to be nearly the same.* The higher cost for Option 2 is due to the use of air-blown Lurgi gasifiers to produce fuel gas for onsite steam and power generation. In all options most of the air pollution control cost is attributed to the costs associated with pollution control for steam and power generation (use of FGD systems/electrostatic precipitators or clean fuel gas). As discussed in Section 2.1.5, the capital and annual operating costs for a 7 x 10^6 Nm^3/d (250 MMscf/d) commercial Lurgi SNG plant have been estimated at approximately $2 billion and $300 million, respectively. Based on these plant costs, the estimated air pollution control costs shown in Table 4-15 represent about 2% to 3% of the capital cost and 4% to 5% of the operating cost.

Table 4-17 presents the estimated energy requirements for air pollution control under the five options. (See Section 7.3 for assumptions and detailed calculations.) The estimated values range from about 65 million to 180 million kcal/hr (260 million to 720 million Btu/hr) for a 7 x 10^6 Nm^3/d (250 x 10^6 scf/d) Lurgi SNG plant, or about 1.5 to 3.1% of total plant input energy. Option 3, which employs ADIP/Claus/Beavon/Stretford processes for treatment of Rectisol acid gases, would have the lowest overall energy requirement while Option 2, which features fuel gas production, is estimated to have the highest requirement. Options 1 and 5 would have about the same energy requirements. In Options 1, 3 and 5 incineration accounts for about one third of the total estimated energy requirement while sulfur removal/recovery from acid gases accounts for over 50% of the total. Except for Option 2, from 12 to 25% of the total energy requirement is attributed to particulate and SO_2 removal from flue gases.

The estimated emissions, costs and energy requirements presented above for Options 1 through 5 have been based on the use of western coal (0.7% sulfur, 4670 kcal/kg or 8400 Btu/lb HHV). A few generalizations can be made on the impact of using eastern coals (higher sulfur content and HHV) on emissions, costs and energy requirements for air pollution control. Use of coals with higher heat content but the same sulfur percentage should produce Rectisol acid gases containing somewhat more CO_2 relative to H_2S and COS. This would not

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*The cost estimate for Option 5 does not include the expected higher cost associated with a modified Rectisol process design to produce a more concentrated acid gas for direct feeding to the Claus plant.

TABLE 4-17. ESTIMATED ENERGY REQUIREMENTS FOR AIR POLLUTION CONTROL OPTIONS* (MILLION KCAL/HR)

Process/Energy Component	Options				
	1	2	3	4	5
Stretford					
Fuel	24.00	27.91	--	--	16.67
Steam	4.20	4.88	--	--	2.92
Electricity	21.10	24.5	--	--	14.66
ADIP					
Steam	--	--	22.57	--	--
Electricity	--	--	0.97	--	--
Claus					
Steam	--	--	1.97 (21.63)†	--	0.66 (7.23)†
Electricity	--	--	0.49	--	0.16
Beavon					
Fuel	--	--	10.05	--	3.35
Steam	--	--	3.10	--	1.03
Electricity	--	--	4.25	--	1.42
Wellman-Lord					
Steam	10.52	--	16.39	94.25	16.39
Electricity	2.12	--	3.39	19.51	3.39
Electrostatic Precipitator					
Electricity	0.29	--	1.21	1.25	0.82
Incineration	28.00		22.37	25.19	27.39
Fuel Gas Production	--	121	--	--	--
TOTAL	90.23	178.29	65.55	140.20	81.63

*See Section 7.3 for flow diagrams, assumptions and detailed calculations.
†Parentheses indicate credit for by-product steam.

greatly impact the cost or performance of Stretford, Claus, Beavon, or incineration processes since the major parameters affecting the cost/performance of these processes are the total sulfur or hydrocarbon loadings rather than concentrations or total gas flow rates. On the other hand, the costs of FGD units and electrostatic precipitators increase in direct proportion to the gas flow rate so that some savings may be realized with particulate and SO_2 removal in SNG plants using higher heat content coals for steam and power generation. The sulfur emissions from either acid gas treatment and flue gas treatment processes are not expected to be significantly affected by the heat content of the coal (provided that the sulfur content remains constant). The use of higher heat content coals results in some increase in the HC and CO in the treated Rectisol acid gases.

When higher sulfur coals are used as feed to Lurgi gasifiers, H_2S and COS levels are expected to increase in Rectisol acid gases in approximate proportion to feed coal sulfur content. If such acid gases are treated in a Stretford unit, the COS will not be removed and will be emitted to the atmosphere unless the Stretford tail gas is further treated. When Rectisol acid gases are handled by the Claus process, tail gas sulfur loading will be in approximate proportion to feed loading. When catalytic reduction processes such as Beavon are used for tail gas treatment, an atmospheric emission of about 250 ppmv total sulfur is expected regardless of feed gas sulfur loading and hence the coal sulfur content.

An increase in sulfur content of coal fed to utility boilers will generally result in an approximately proportional increase in flue gas sulfur emissions after treatment by SO_2 removal systems. Similarly, Claus or Stretford tail gas treatment by SO_2 removal systems will result in an approximately constant percent removal, independent of the feed gas sulfur level and coal sulfur content. Hence, the use of higher sulfur coal will increase sulfur emissions for the SO_2 removal systems.

The general effect of increasing feed coal sulfur content will be to increase total plant sulfur emissions. The contribution to total emissions from steam and power generation will usually be greater for high sulfur feeds. When all SNG plant sulfur-bearing waste gases are combined for treatment by SO_2 removal processes (e.g., Option 4), the relative contribution of flue gases and acid gases to total emissions will also be independent of feed sulfur levels.

In general, the air pollution control energy requirements are expected to increase with the rise in the coal sulfur content, due to the increase loading on (and regeneration/sludge disposal requirements for) FGD and sulfur recovery systems. A rise in the heat content of the coal increases the acid gas volumes to be treated and hence the energy requirement for acid gas/tail gas treatment for sulfur, CO and HC control.

4.3 WATER EFFLUENT CONTROL ALTERNATIVES

This section defines and evaluates water pollution control alternatives and practices which may be employed in commercial Lurgi SNG facilities. Figure 4-2 presents the process modules for treatment of the aqueous waste streams identified in Section 3.6. One additional type of aqueous waste shown in Figure 4-2 (waste sorbents/reagents), which was not discussed in Section 3.6, is also discussed in this section. Table 4-18 presents the wastewater treatment processes in each module which would have potential application to wastewater streams in a commercial Lurgi SNG system. The discussion which follows is organized according to the origin of wastewater streams in Lurgi SNG facilities.

TABLE 4-18. WASTEWATER TREATMENT PROCESSES POTENTIALLY APPLICABLE TO COMMERCIAL LURGI SNG SYSTEMS

Oil and Suspended Solids Removal: gravity separation (API separators), flotation, coagulation-flocculation, filtration

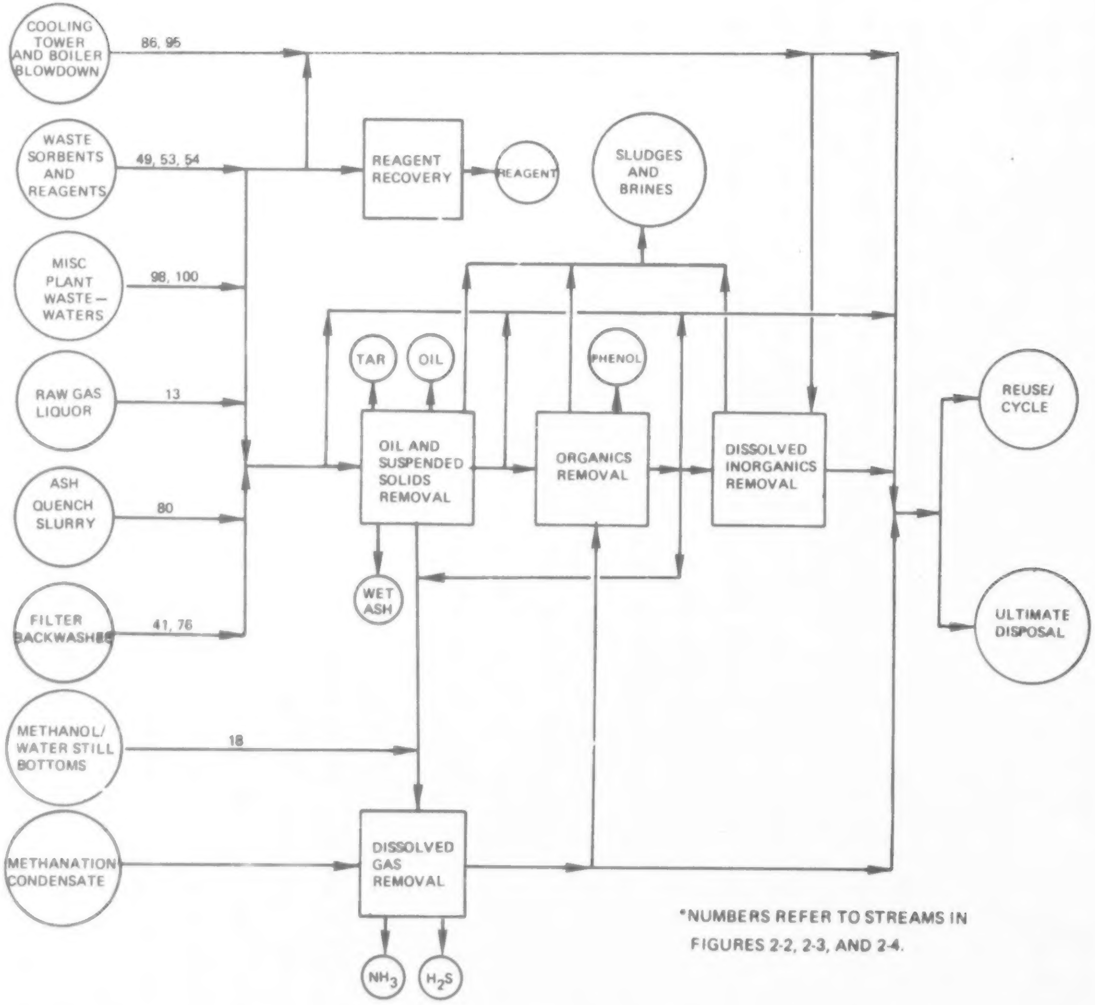
Dissolved Gases Removal: conventional steam stripping, Chevron WWT, Phosam-W, Lurgi-Chemi Linz AG ammonia recovery processes

Dissolved/Particulate Organics Removal: Phenosolvan process, biological oxidation, chemical oxidation, activated carbon adsorption, adsorptive resins

Separated Tar/Oil and Sludge Treatment: emulsion breaking, gravity thickening, centrifugation, vacuum filtration, drying beds

Dissolved Inorganics Removal: ion exchange, reverse osmosis, electrodialysis, freezing, electrochemical treatment, distillation

Ultimate Disposal: evaporation ponds, deep well injection


COOLING TOWER AND BOILER BLOWDOWN
86, 95
WASTE SORBENTS AND REAGENTS
49, 53, 54
MISC PLANT WASTE-WATERS
98, 100
RAW GAS LIQUOR
13
ASH QUENCH SLURRY
80
FILTER BACKWASHES
41, 76
METHANOL/ WATER STILL BOTTOMS
18
METHANATION CONDENSATE
REAGENT RECOVERY
REAGENT
SLUDGES AND BRINES
TAR
OIL
PHENOL
OIL AND SUSPENDED SOLIDS REMOVAL
ORGANICS REMOVAL
DISSOLVED INORGANICS REMOVAL
WET ASH
DISSOLVED GAS REMOVAL
NH_3
H_2S
REUSE/ CYCLE
ULTIMATE DISPOSAL

*NUMBERS REFER TO STREAMS IN FIGURES 2-2, 2-3, AND 2-4.

Figure 4-2. Process Modules for Water Pollution Control in Lurgi SNG Facilities

4.3.1 Coal Pretreatment and Handling

No aqueous process waste is produced in the coal preparation operation. Coal pile runoff, however, is generally associated with coal storage and handling. The runoff is most effectively controlled through measures to minimize runoff generation (e.g., by division of storm runoff from adjacent areas) and collection of the pile runoff for treatment with other plant wastewaters and/or process use.

4.3.2 Coal Gasification

The ash quench slurry is the only aqueous waste stream associated with the gasification operation. Commonly, low quality plant waters are used to quench ash. The resulting slurry is transported to a ash thickening unit where bulk solids are separated for disposal and the thickener overflow is recycled or sent to further treatment by clarification in a settling basis or lagoon.

The thickeners and clarifiers which would be used in commercial Lurgi SNG facilities would be similar to the systems employed in the utility and other industries for the management of high solid content ash slurries and inorganic sludges. The specific design and costs of these systems are affected by the characteristics of the slurries handled (i.e., solids concentration, settleability, temperature, etc.) and the desired degree of thickening and clarification. The desired degree of thickening and clarification are in turn dependent upon the method of sludge and clarified effluent disposal (e.g., use of onsite sludge lagoons, transportation and disposal of sludge to offsite facilities or return to mines; ultimate disposal of effluent by solar or forced evaporation, and discharge to receiving water or reuse in the process). In a Lurgi SNG facility, therefore, the design and cost of ash slurry thickening/clarification cannot be considered independent of the total plan for wastewater and solid waste management for the facility. At present no engineering data are available on the characteristics of Lurgi ash slurry to permit accurate estimation of the performance and costs of thickener/clarifiers for handling Lurgi ash slurry. Based on applications to municipal wastewaters and sludges, the capital cost for a 34-m (112-ft) diameter thickener would be about \$280,000; the annual operating cost for such a unit is about \$18,500(75).

4.3.3 Gas Purification

Two aqueous waste streams are generated as a result of purification of the raw product gas. These are raw gas liquor and methanol/water still bottoms. The raw gas liquor is ordinarily treated for the recovery of tars and oils, phenols and ammonia. The still bottoms are generally treated in the ammonia recovery unit.

Tar and Oil Recovery. In the designs for all proposed Lurgi SNG facilities, raw gas liquor treatment for tar/oil/water separation consists of dissolved gas flotation/gravity settling. As discussed in Section 2.2.6, tar/oil separators employed in Lurgi systems operate on the flotation principle in that the reduction in pressure results in the release of dissolved gases which float oil to the surface for recovery. These separators achieve a high removal efficiency (up to 99% suspended tar and oil removal(7)) and are very cost effective since they take full advantage of the inherent characteristics of the raw gas liquor (i.e., having dissolved gases under pressure). The capital cost for a Lurgi tar and oil separation unit in a 7 x 10^6 Nm^3/d (250 x 10^6 scf/d) SNG plant is estimated at about $13 million (1975 dollars) or about 2% of the total plant investment(25). Alternatives to the Lurgi tar/oil/water separation process, which include gravity separation using API separators, gravity separation enhanced by chemical coagulation and flocculation, and filtration, do not offer any cost or performance advantage and hence have not been featured in any of the designs for proposed commercial Lurgi SNG facilities.

Phenol Recovery. The treated gas liquor from the tar and oil recovery system contains a high concentration of phenols (see Tables 3-20 and 3-22) which can be recovered as a valuable by-product. The Phenosolvan process is usually employed in Lurgi systems for phenol recovery (see Section 2.2.6 for process description). Most of the available data on the performance of the Phenosolvan process are for the unit in Sasolburg, South Africa. This unit is reported capable of achieving an effluent containing 1 ppm of steam volatile phenols and 60 ppm of total phenols(44). The detailed characteristics of the influent fed to the Phenosolvan unit (separated gas liquor) and the effluent after phenol and ammonia recovery (cleaned gas liquor) have been presented in Tables 3-22 and 3-24. As indicated by the data in these tables, the Phenosolvan and the stripping processes can achieve significant removals of organics other than phenols; a total COD removal of about 90% is achieved. The high degree of organics removal reduces the organic loading on subsequent wastewater treatment for pollution control.

No capital and operating cost information could be obtained in this study on the use of the Phenosolvan process for phenol recovery. However, estimates have been made for the cost of a solvent extraction system (benzene as the solvent) for application to gas liquor. For a typical unit in a commercial size plant handling about 8000 l/min (2000 gpm) of gas liquor containing 6000 ppm of total phenol, a capital cost of \$9.2 million and a total annual cost of \$3.6 million have been estimated(76) (1977 dollars). Considering the very high concentration of phenols and the nature and concentration of other organic and inorganic constituents in the Lurgi gas liquor, solvent extraction appears to be the most cost effective method for handling this stream. This has been confirmed in a recent engineering study(77) where solvent extraction was compared with two alternative treatment methods involving resin adsorption and biological oxidation.

Ammonia Recovery. Lurgi gas liquor contains a high concentration of ammonia (and a smaller concentration of hydrogen sulfide, hydrogen cyanide and carbonyl sulfide). Ammonia is commonly recovered as a saleable by-product by stripping. The recovery of ammonia also significantly reduces the waste loading on downstream wastewater treatment units. Although in a Lurgi SNG facility stripping is primarily aimed at the recovery of ammonia from the separated gas liquor, the process also results in the generation of an overhead gas containing recoverable amounts of H_2S. As discussed in Section 4.2.3, the overhead gas is usually treated in combination with the Rectisol acid gases in a sulfur recovery unit.

Stripping can be effected by contacting the wastewater with a stripping medium such as steam, flue gas, nitrogen, air and carbon dioxide. The most common stripping medium is steam and the stripping operation is usually conducted in a tower (packed or trays). Acid (for sulfide) or alkali (for ammonia) may be added to the raw wastewater to improve stripping efficiency. Steam stripping is widely used in refineries for the treatment of sour waters containing ammonia and/or hydrogen sulfide. In these applications the stripped gases are either disposed of by flaring or processed for the recovery of anhydrous or aqueous ammonia or ammonium sulfate, elemental sulfur (in a Claus plant) or sulfuric acid. In many cases, the flaring of stripper off-gases is being phased out due to SO_2 and NO_x limitations. Conventional steam stripping of the refinery sour water can achieve up to 95% removal of NH_3 and greater than 99% removal of H_2S, with residual NH_3 and H_2S concentrations typically less than 50 ppm and 10 ppm, respectively(58). Since low molecular weight phenols are somewhat volatile, sour water stripping can also result in the partial removal of phenols (up to 70% in refinery applications; in these applications residual phenol levels of 30 to 110 ppm have been reported).

Two patented applications of steam stripping which generate separate concentrated NH_3 and H_2S streams are the Chevron WWT and the USS Phosam W processes. In the Chevron process separate towers which operate under different pressures and temperatures are used for NH_3 and H_2S stripping. The residual H_2S contained in the product ammonia stream is removed by scrubbing the gas stream with liquid ammonia. The treated gas is then processed to convert the gaseous ammonia to anhydrous or aqueous ammonia or to ammonium sulfate. The treated wastewaters from the Chevron process can have residual H_2S and ammonia as low as 5 and 50 mg/l, respectively(73). The USS Phosam W process, which has been designed for application to coke oven gases, features the circulation of ammonium phosphate solution in the upper portion of the stripper to absorb the ammonia from the product stripping gases, leaving an H_2S stream containing low levels of ammonia. The ammonia-rich phosphate solution is steam stripped in a separate vessel at elevated pressure and temperature, producing an ammonia-rich stream which is subsequently condensed in a fractionating column to produce anhydrous ammonia. Removal efficiencies of over 99% for both H_2S and NH_3 are claimed for this process(1).

The Chevron WWT and USS Phosam W processes have not been employed at pilot or commercial gasification facilities to date. Conventional steam stripping with ammonium sulfate recovery, however, has been used at the SASOL gasification complex(44). The USS Phosam W process has been incorporated into the design of the proposed ANG (North Dakota) SNG plant(15). A recent engineering study by C. F. Braun and Company comparing various stripping processes for application to coal gasification wastewaters indicates that both USS Phosam W and the Chevron WWT processes have higher capital and operating costs than conventional sour water stripping without by-product recovery(79). The value of the recovered ammonia, however, significantly offsets the added costs for both processes.

One cost estimate for a Phosam W plant handling 13.7×10^6 l/d (3.6×10^6 gal/d) of sour water* is that a capital investment of 8.2 million 1975 dollars is required(76). Operating costs for such a plant are about one dollar/1000 ℓ ($4/1000 gals) of feed. Sale of ammonia offsets about $0.14/1000 ℓ ($0.55/1000 gals) of the cost.

Lurgi-Chemi Linz AG is a Lurgi-licensed stripping process for ammonia recovery, which is reported to be in service at certain Lurgi facilities abroad(4). No data, however, are available on the operating features and economics of this process.

Treatment of Rectisol Methanol/Water Still Bottoms. This stream represents a relatively small flow compared to raw gas liquor (about 6% of gas liquor volume(31)) and contains low levels of dissolved gases and organics. Ordinarily, this stream would be combined with gas liquor after tar/oil separation or phenol removal and treated for ammonia removal.

4.3.4 Gas Upgrading

Methanation and dehydration condensates are the only aqueous wastes generated in the gas upgrading operation. These condensates, which contain only very low levels of dissolved solids and no ammonia and H_2S, are considered "clean" streams. After degasification (to remove methane and carbon dioxide), the condensates would be suitable for use as boiler feed water. Alternatively, the condensates can be used as cooling tower makeup or as process water.

4.3.5 Auxiliary Processes

As discussed in Section 3.6.5, major aqueous waste streams associated with auxiliary processes are clean gas liquor, filter backwashes, waste sorbents and reagents, cooling tower and boiler blowdowns and miscellaneous plant wastewaters. Processes for the control of each of these classes of wastewaters are reviewed in this section. In addition, a discussion of the water pollution control and ultimate wastewater disposal options in an integrated facility is provided.

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*Approximate sour water flow rate for the proposed El Paso-Burnham Lurgi SNG plant (7×10^6 Nm^3/day or 250×10^6 SCF/day).

Treatment of Clean Gas Liquor. As noted in Tables 3-22 and 3-24, the clean gas liquor from the ammonia recovery unit contains considerable organic loading, and from this standpoint is the most important waste stream in a Lurgi SNG plant. The clean gas liquor can be treated by any of the number of conventional wastewater treatment processes for organics removal. These processes include: biological oxidation, chemical oxidation, activated carbon adsorption and organic resin adsorption.

In biological oxidation, the dissolved and/or collodial organics are converted to inorganic end products and microbial cells by the action of microorganisms. The resulting biomass (sludge) is subsequently removed by gravity separation. Although biological oxidation can be conducted under anaerobic (absence of oxygen) conditions, for most applications aerobic (in the presence of oxygen) treatment is preferred because of the higher efficiency and lower costs. Biological treatment has been widely employed for the treatment of industrial wastes and municipal sewage. Table 4-19 lists the most commonly used biological treatment systems including reported efficiency ranges for the removal of BOD, COD, SS, oil, phenols and sulfide in applications to refinery wastewaters. As noted in the table, biological treatment can result in up to 90% removal of the biologically oxidizable compounds. Although not classified strictly as waste stabilization ponds, evaporation and retention ponds which are widely used in industry for ultimate disposal of raw or treated wastewaters, and which serve as tertiary treatment basins following biological treatment or as temporary storage ponds for controlled effluent discharge, do achieve some biodegradation of organics.

The use of pure oxygen (in place of air) in the biological treatment of wastewaters by the activated sludge process has received considerable attention in recent years and a number of pure oxygen activated sludge plants are currently in operation handling municipal sewage and a variety of industrial wastewaters. Compared to the conventional air activated sludge process, the pure oxygen process is claimed to have several advantages, including higher efficiency and throughput rate, less sludge production, superior characteristics of the sludge, and lower overall costs. The use of the oxygen activated sludge process in a Lurgi SNG plant is especially attractive since such a plant employs onsite oxygen production and hence a source of oxygen would be available for wastewater treatment.

TABLE 4-19. EFFICIENCY OF BIOLOGICAL TREATMENT FOR PETROLEUM REFINERY EFFLUENTS(81)

Biological Treatment Method	Parameter* (% Removal)					
	BOD	COD	Suspended Solids	Oil	Phenols	$S^=$
Activated sludge	88-90	60-85	-	-	95-99+	97-100
Trickling filters	60-85	30-70	50-80	50-80	-	-
Waste stabilization pond (aerobic)	40-95	30-65	2-70	50-90	-	-
Aerated lagoons	75-95	60-85	40-65	70-90	90-99	95-100
Cooling tower oxidation	90+	90+	-	-	99.9	-
Spray Irrigation	95+	90+	99+	70-90	99.9	99+

*Approximately 70 percent of thiocyanates are removed by all processes.

Cooling towers for biological treatment of selected waste streams have been used successfully in refineries and have been demonstrated at the SASOL (South Africa) gasification plant (80). Cooling towers provide ideal temperatures and surfaces for biological activity. The oxygen required by microorganisms are provided by extensive aeration which accompanies the cooling process. In refinery applications, phenolic wastewaters have been used as cooling water make-up and more than 99% destruction of phenols has been reported(81). In a demonstration program at the SASOL plant, the ammonia stripper bottoms have been used as cooling tower make-up. In this program the bioactivity, foaming, fouling and corrosion which may be expected from the use of this wastewater for cooling water make-up have been evaluated and the results have been used as a basis for the design of a cooling/oxidation tower system for the proposed El Paso Burnham plant in New Mexico(2). Other proposed designs such as the American Natural Gas Company's design in North Dakota also feature the use of towers for biological treatment(15).

Biological treatment may also be accomplished by the application of raw or partially treated wastewaters to soils. Microbiological processes in the soil can result in the degradation of most organics and the oxidation of ammonia, sulfide, and other pollutants. In addition, physical adsorption and filtration can result in the removal of phosphorus and some metallic elements. Depending on the particular soil, the geographic location, and the rate of wastewater application, net runoff or percolation may or may not be generated. Continued application of wastewaters containing high levels of dissolved solids to soils can result in salinity and/or alkalinity buildup to the point of adversely affecting plant growth. The accumulation of certain trace elements and organics in soils may also present toxicity problems for plants or herbivores.

Several factors affect the applicability and performance of biological oxidation. These factors relate to wastewater constituent biodegradability, toxicity, pH. nutrient content and fluctuations in characteristics. As noted previously, organics in Lurgi gas liquor tend to be highly aromatic. While certain aromatic compounds such as simple phenols are readily degradable (at relatively dilute levels), the more complex and substituted phenols, polycyclic hydrocarbons, and heterocyclic organics are generally less readily degradable or essentially non-biodegradable (e.g., pyridine). The biodegradability of the organics in coal gasification wastewaters is currently under investigation(32).

Some of the organics (e.g., phenols), trace elements (e.g., arsenic and mercury) and inorganic anions (e.g., cyanide and thiocyanate) can be toxic to microorganisms at high concentration levels. Biological processes are generally most efficient when the pH of the wastewater is in the 6-8 range. The pH of the wastewater also affects the toxicity of certain wastewater constituents. For example, the toxicity of sulfide increases with decreasing pH. Nutrients such as nitrogen and phosphorus compounds are necessary for microbiological growth. A BOD:N:P ratio of approximately 100:5:1 is generally necessary for the biological treatment of most industrial wastewaters. When a wastewater is deficient in nutrients, such nutrients must be added to the raw wastewater prior to biological treatment. Lurgi gas liquor has a sufficient amount of nitrogen but is deficient in phosphorus content. At the SASOL Lurgi plant where trickling filters are used for biological wastewater treatment, phosphate is added to the raw wastewater to allow efficient biological treatment(44).

Very little data are available on the performance of biological treatment processes applied to either raw or clean Lurgi gas liquors. Bench-scale experiments with Lurgi gas liquors, however, have indicated that up to 70% COD reduction from raw liquor can be achieved by biological oxidation, while only 20-35% COD reduction is achieved with clean gas liquor(56). These results suggest that solvent extraction for phenol recovery and stripping for ammonia recovery selectively remove the biodegradable organics and that residual organics in clean gas liquor would be less readily biodegradable.

Although actual cost data are not available for the biological treatment of Lurgi gas liquor, the economics of four types of biological processes in coal gasification applications have been estimated(76). As indicated in Table 4-20, the trickling filter-oxygen activated sludge system provides the lowest total annual cost compared to the other listed alternatives. Also shown by the data is the high cost of nitrification-denitrification processes.

In addition to biological treatment, three other types of organics removal processes are potentially applicable to Lurgi gas liquors. These are chemical oxidation, activated carbon adsorption, and resin adsorption. Chemical oxidation processes using oxidants such as ozone and chlorine compounds have been used in industry for the treatment of cyanide, sulfide and thiocyanate wastes. Under proper conditions, ozonation may also affect destruction of biologically refractory organics. The potential application of chemical treatment in a Lurgi SNG facility would probably be limited to wastewater polishing after biological treatment. Bench scale ozone treatment of raw gas quench condensate for another gasification process (the Synthane process) has indicated that complex organics (e.g., quinolines and indanols) and inorganics (e.g., SCN^-) can be largely removed with adequate ozone dosage(83).

Both granular and powdered activated carbon have been used for the treatment of industrial and municipal wastewaters. Being a physical process, carbon adsorption is unaffected by the presence of toxic constituents in the wastewater and the fluctuations in wastewater characteristics.* Granular carbon is

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*When granular carbon is used in beds, some biological growth becomes established in the bed which contributes to the overall organic removal efficiency (via biodegradation). In this case the treatment efficiency would be affected by the presence of toxic chemicals or by wide fluctuations in wastewater characteristics.

TABLE 4-20. ESTIMATED COSTS ASSOCIATED WITH BIOLOGICAL TREATMENT OF WASTEWATERS FROM COAL GASIFICATION PLANTS(76)

	Capital Costs 10^6\$/1000 ℓ (10^6 \$/1000 gals)	Total Annual Costs Dollars/1000 ℓ (Dollars/1000 gals)
Air Activated Sludge System	2.7 (10.1)	0.84 (3.2)
Air Activated Sludge/ Nitrification-Denitrification System	4.6 (17.6)	2.8 (10.61)
Oxygen Activated Sludge System	2.4 (9.09)	0.95 (3.61)
Trickling Filter-Oxygen Activated Sludge System	2.3 (8.68)	0.82 (3.10)

used in fixed or moving columnar beds with either upward or downward wastewater flow. Powdered carbon is generally mixed with the wastewater and is subsequently removed by settling and/or filtration. Because of its relatively high cost, the use of activated carbon adsorption for wastewater treatment would generally be limited to: (1) removal of residual organics from the biological treatment effluents, when such removal is necessary; (2) treatment of wastewaters containing high levels of refractory organics or toxic chemicals; (3) use in combination with chemical coagulation and filtration in a "physical-chemical" combination treatment scheme in lieu of biological treatment, and (4) recovery of by-products (e.g., phenols) from the wastewaters. Except when used for by-product recovery, the spent carbon is usually regenerated by thermal treatment. In polishing of biologically-treated refinery and coke plant wastes, removal efficiencies of up to 80% COD, 90% TOC, and over 99% phenols have been reported for granular carbon adsorption(84,85). Similar removal efficiencies would be expected for polishing applications to biologically-treated Lurgi clean gas liquor. Capital and operating costs of granular carbon systems depend upon the specific design and the nature and volume of the wastewater treated. One estimate of 1976 capital costs is as follows(86):

Adsorption Equipment

Flow	Cost ($)
4×10^5 ℓ/day (1×10^5 gal/day)	180,000
4×10^6 ℓ/day (10^6 gal/day)	550,000

Regeneration Equipment

Carbon Usage Rate	Cost ($)
910 kg/day (2000 lbs/day)	270,000
8200 kg/day (18000 lbs/day)	1,000,000

1976 operating costs have been estimated at about $0.68 per 1000 liters ($2.63 per 1000 gal) for every 1000 mg/l of COD removed(76).

Even though at the present time powdered and granular carbon are the sorbents of choice for removal of residual or refractory organics, other methods are being developed as alternatives to carbon or for specialized applications.

One of the more promising of these methods involves the use of macroreticular polymeric adsorbents such as the Amberlite XAD-8 synthetic resin which have the ability to sorb organics without any substantial inorganic exchange capacity. The XAD-8 and similar resins have been successfully used for the decolorization of Kraft pulp bleaching effluent. The sorptive resins are usually regenerated by elution with aqueous solutions of proper pH or with organic solvents. Cost data for large-scale resin application to wastewaters are generally not available.

Treatment of Filter Backwashes. Relatively small volumes of wastewaters with high suspended solids/suspended organics would be generated by backwashing of filters which are used ahead of the Phenosolvan unit (to remove suspended solids from the separated gas liquor) and for raw water treatment. These wastewaters would most likely be sent to the ash/water clarification system for treatment.

Control of Waste Sorbents and Reagents. Sulfur recovery, air pollution control and raw water treatment processes employed in a Lurgi SNG facility would produce waste sorbents and reagents in the form of brines, sludges, and blowdowns. The specific nature of such wastes will depend upon the specific processes employed. As discussed in Section 4.2, major candidate pollution control processes which generate waste sorbents/reagents include the Stretford process, the Wellman-Lord process, the Chiyoda Thoroughbred 101 process, the lime/limestone scrubbing process, and the Dual Alkali process.

The reagent purge in the Stretford process contains 200 to 300 g/l of salts (mainly thiosulfate, thiocyanate and carbonate salts of sodium with smaller amounts of vanadate and anthraquinone disulfonate). There are two commercially available processes for treatment of the Stretford purge which also provides for the recovery of sodium and vanadium salts for reuse. Nittetu Chemical Engineering (NICE) has developed the process shown in Figure 4-3 for recovering the sodium value in the purge solution. The purge solution is first evaporated at 333°K (140°F) and a partial vacuum of 13 Pa (2 psia) using the quenched combustion gas at 363°K (194°F) for the energy source. The concentrated waste (~50% salts by weight) is incinerated in a reducing atmosphere maintained by limiting oxygen in the combustion process to 70 to 80% of the theoretical amount required for combustion. The sodium salts converted to Na_2CO_3 and $NaHCO_3$ are quenched with the combustion gas. The Na_2CO_3 solution from the quench tank is

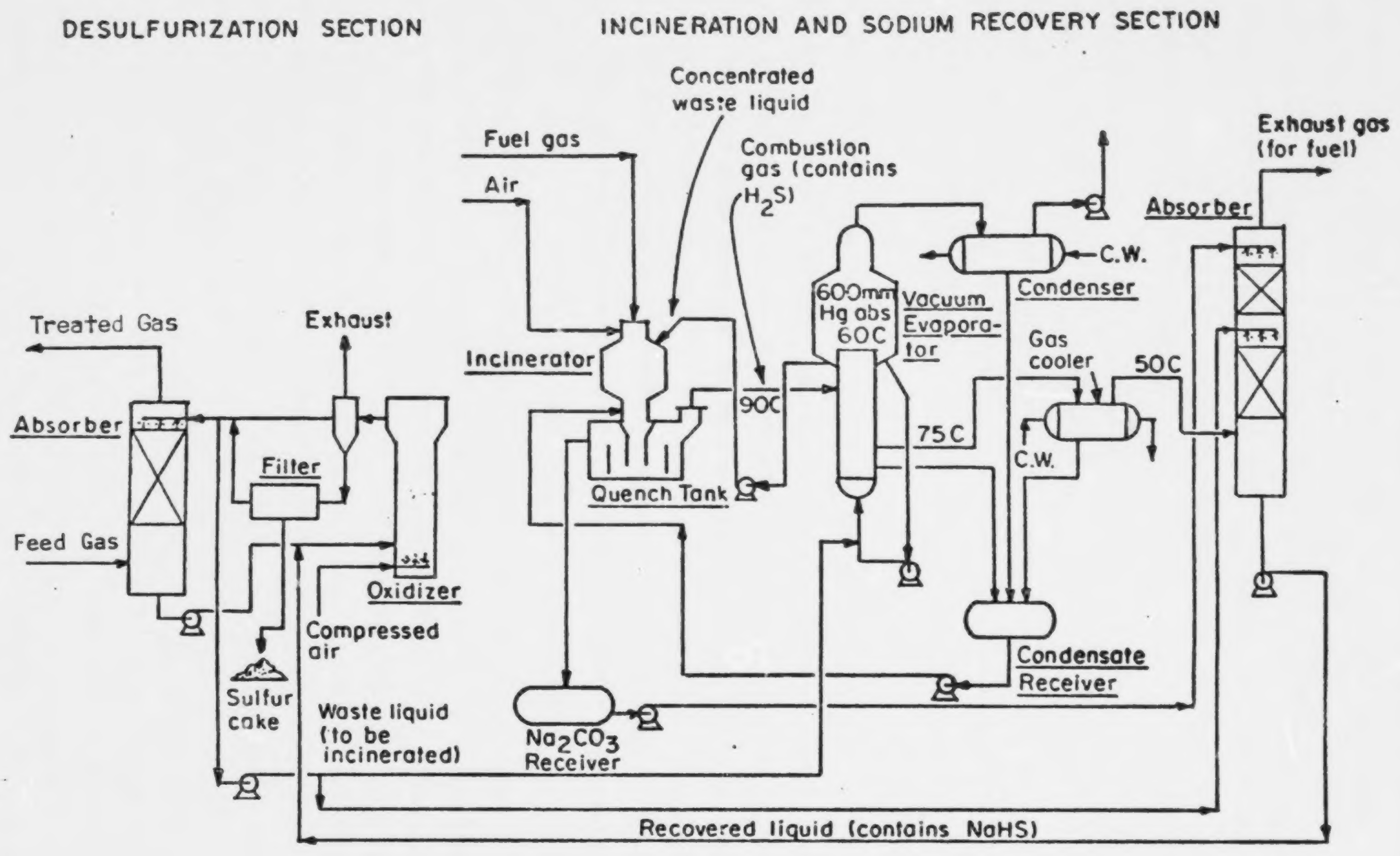

DESULFURIZATION SECTION
INCINERATION AND SODIUM RECOVERY SECTION
Treated Gas
Absorber
Feed Gas
Exhaust
Filter
Sulfur cake
Oxidizer
Compressed air
Waste liquid (to be incinerated)
Fuel gas
Air
Incinerator
Concentrated waste liquid
Combustion gas (contains H_2S)
Quench Tank
90C
Na_2CO_3 Receiver
600mm Hg abs 60C
Vacuum Evaporator
75C
Condenser
C.W.
Gas cooler
C.W.
50C
Condensate Receiver
Absorber
Exhaust gas (for fuel)
Recovered liquid (contains NaHS)

Figure 4-3. Treatment of Stretford Process Purge Solution by the NICE Process(87)

removed continuously and used as sorbent in the H_2S absorber of the Stretford process.

Another commercially available treatment process which is licensed by Woodall-Duckham USA Ltd. recovers both sodium salts and vanadium by a high temperature hydrolysis process(88). In this recovery-treatment process (see Figure 4-4) the liquid is first concentrated in an evaporator. The concentrated solution is fed to a high temperature hydrolyzer, where the solution is evaporated to dryness and decomposed in a high temperature reducing environment. The reducing atmosphere is produced by stoichiometric combustion of fuel. Gases rich in H_2S leaving the process are cleaned of solids in cyclones and are fed to the Stretford absorber. The solids, containing vanadium and sodium, are dissolved and recycled to the Stretford plant. It is claimed that the process breaks down all of the thiocyanate, most of the thiosulfate, and more than half of the sulfate in the effluent.

Stretford purge may also be treated without resource recovery. Biological treatment is feasible if the waste is diluted with other plant wastes to reduce thiosulfate and thiocyanate levels(89). Alternatively, the purge could be used for ash quenching, thus allowing ultimate disposal to be combined with ash quench water disposal. At present there are no data to indicate the costs associated with either resource recovery or waste treatment processes applied to Stretford purge.

The Wellman-Lord, Chiyoda Thoroughbred 101, and the Dual Alkali processes generate aqueous wastes containing primarily dissolved inorganic salts. The Wellman-Lord process produces an aqueous sodium sulfate/sulfite purge. The Chiyoda Thoroughbred 101 process produces an acidic aqueous purge solution which contains H_2SO_4, MgO with traces of $Fe_2(SO_4)_3$. The Dual Alkali process produces an alkaline purge containing mainly calcium hydroxide. Treatment alternatives for these wastes include resource recovery via processes such as those employed for Stretford purge; dissolved solids removal by evaporation, ion exchange, etc., and use of the wastes as ash quench makeup with subsequent treatment of the ash quench slurry. The latter alternative has been included in the designs for the proposed commercial Lurgi SNG plants.

Lime/limestone scrubbing generates a sludge containing mainly calcium sulfate/sulfite solids. The only practical treatment method for such sludge is concentration in a thickener or quench slurry system for combined treatment.

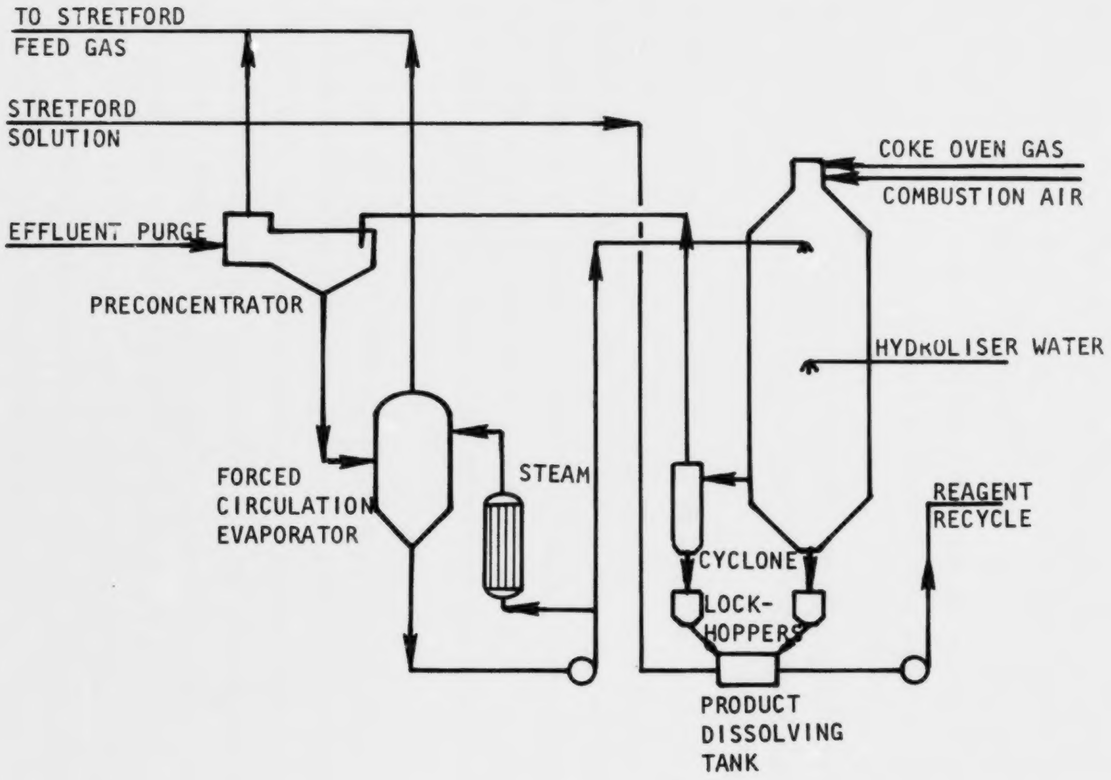

TO STRETFORD
FEED GAS
STRETFORD
SOLUTION
EFFLUENT PURGE
PRECONCENTRATOR
FORCED
CIRCULATION
EVAPORATOR
STEAM
COKE OVEN GAS
COMBUSTION AIR
HYDROLISER WATER
CYCLONE
LOCK-
HOPPERS
REAGENT
RECYCLE
PRODUCT
DISSOLVING
TANK

Figure 4.4. Woodall-Duckham High Temperature Hydrolysis Process for Stretford Effluent Treatment(83)

Brines generated by ion exchange and demineralization units used for boiler water treatment and sludges resulting from lime softening/clarification of raw plant water are not unique to coal gasification facilities but rather are common to many industrial facilities. In gasification plants, however, such wastes would commonly be disposed of with the ash quench slurry rather than by direct discharge or separate disposal. Deep well injection for the disposal of brines is also featured in the designs for some proposed commercial Lurgi SNG plants. (See the "Ultimate Disposal of Wastewaters," Section 4.3.5, and "Summary of Water Standards," Section 5.3.1, for discussions of limitations of and regulations governing deep well disposal.)

Treatment of Cooling Tower and Boiler Blowdowns. As is common practice in many industries, in a Lurgi gasification facility the boiler blowdown can be used as cooling tower makeup since the blowdown is relatively low in dissolved solids and contains no other constituents which would ordinarily interfere with the operation of cooling systems. The cooling tower blowdown can be used for ash quenching and dust suppression. Alternatively, the cooling tower blowdown may be treated (e.g., by ion exchange or forced evaporation) to recover water for reuse (see the section on wastewater management in integrated facilities for a description of the dissolved solids removal process).

Control of Miscellaneous Plant Wastewaters. In addition to the wastewaters discussed above, several miscellaneous wastewaters are generated in an integrated Lurgi SNG facility which require control. Perhaps the most important of these are plant runoff, sanitary wastes, and water separated from by-products during storage. Plant runoff would generally be collected by a sewer system and stored for treatment for the removal of separable oils and other suspended solids prior to reuse or discharge.

Gravity separation is usually the first step in the treatment of wastewaters for the removal of bulk separable oil and suspended solids. "API separators", which are gravity separators designed in accordance with the criteria suggested by the American Petroleum Institute (API), are widely used in petroleum refineries for the treatment of oily wastewaters. Gravity separation is also used following biological or chemical treatment for the removal of biological and chemical flocs. In gravity separation the wastewater is allowed to undergo "quiescent settling" in a basin. The oil globules, which are lighter than water, float to and are collected at the surface; the settleable solids settle to the bottom and are removed as sludge. The settling basins are usually rectangular or circular in shape with "accessories" for the introduction of raw wastewater and collection of effluent, sludge and/or oil. To maximize space utilization, the settling basin design may incorporate use of inclined parallel plates/tubes, each representing a "mini basin" within which solid-liquid separation takes place. The efficiency of gravity separation is dependent on the wastewater characteristics and the hydraulic surface area loading of the basin. The following ranges of removal efficiencies have been reported for the API separators in refinery oil-water separation applications: 10-50% suspended solids, 50-99% free oil, 3-35% BOD, and 5-30% COD(90). The capital cost for API separators varies with the desired effluent oil concentration. For example, for a 3780 l/min (1000 gpm) unit, the capital costs (adjusted to 1978 dollars) are estimated at $500,000 and $1,000,000 for effluent oil levels of 100 ppm and 50 ppm, respectively(38). The operating cost for a 3780 l/min (1000 gpm) unit is estimated at $118,000/year (adjusted to 1978 dollars).

Prior to entering gravity separator units, chemicals such as iron and aluminum salts and polymeric organics are sometimes added as coagulant aids to improve the efficiency of gravity separation and flotation operations. When added to wastewaters in relatively small quantities, these chemicals can destabilize colloidal particles and agglomerate fine particles into larger flocs which settle or rise at a faster rate. Particle growth is often facilitated by gentle mechanical mixing (flocculation). When used in conjunction with API separators or dissolved air (or gas) flotation units, coagulation-flocculation can increase removal efficiencies and/or enable higher throughput rates.

Filtration may also be employed for suspended solids removal. Generally, filtration follows conventional treatment such as gravity separation, chemical treatment or biological oxidation. Filtration is usually accomplished using a bed of inert solids such as sand, diatomaceous earth or anthracite. The suspended solids trapped in the filter are periodically removed from the filter by backwashing. As a polishing step for the API separator effluent, sand filtration has been reported to achieve the following removal efficiencies: 70-75% suspended solids, 52-83% free oil, 25-44% COD and 36% BOD(90).

Sanitary wastes at gasification plants would be handled in one of two ways. Being very small in volume relative to other plant wastes (e.g., gas liquor), it may be combined with such wastes and treated jointly by biological oxidation. Alternatively, sanitary waste may be treated separately in "package" units as is common practice in many industries. The joint treatment of the sanitary and process wastes is often desirable since the sanitary waste provides some of the nutrients (e.g., phosphorus) required for effective biological treatment.

Water which separates from tars, oils and naphtha during storage will require treatment for dissolved and suspended organics removal. Although little information is available regarding the quantity (if any) and characteristics of separated water, it may be expected that such water will be "bound" in sludges or emulsions. The handling of sludges and emulsions is discussed in Section 4.4.

Wastewater Management at Integrated Facilities and Associated Costs and Energy Requirements. The types and characteristics of the wastewaters generated in an integrated Lurgi SNG plant and hence the available options for wastewater management are determined by a number of factors, the most important of which are: (a) the type of coal gasified; (b) the air pollution control and sludge/solid waste management processes used; (c) the availability and cost of raw water; (d) the climate, geographical location of the plant and land availability; and (e) the discharge regulations. Wastewater management in large industrial facilities such as integrated commercial gasification plants would provide for wastewater segregation, by-product recovery, wastewater treatment, water reuse and recycling, good housekeeping practices, treatment of separated tar/oil and sludges, and ultimate disposal of treated wastewaters. A brief review of these approaches to wastewater volume and concentration reduction follows. (Recovery of phenols, tar and oil and ammonia as by-products were discussed in Sections 2.2.6 and 4.3.3. Treatment of separated tar/oil and sludges will be discussed in Section 4.4 in connection with solid waste management.) Also presented in this section is a brief review of costs and energy requirements for wastewater treatment in integrated facilities.

- Wastewater Segregation. Separation of dilute and concentrated wastewaters and wastewaters of significantly different composition can often provide for more effective and economical treatment of the separated streams and in some cases, enable cost-effective by-product recovery and water reuse/recycle. Most refineries use a system of segregated sewers for separate collection, transportation and treatment of sour waters, oily waters, relatively "clean" process waters and storm runoff. Similar systems of waste segregation are used in existing Lurgi coal gasification plants abroad, and are included in the designs for the proposed Lurgi SNG facilities in the U.S. The wastewater management system for the proposed El Paso Lurgi SNG plant is shown in Figure 4-5.

Some of the key features of wastewater segregation schemes at a Lurgi SNG facility are as follows. Low quality wastewaters high in dissolved and suspended solids may be combined and treated together. Waste streams that fall in this category are cooling tower blowdown, ash quench slurry and brines and sludges from raw water treatment units.

Organics-containing wastewaters such as the clean gas liquor and plant runoff may be combined and treated jointly by biological oxidation. Wastewaters low in total dissolved solids may be separated from wastewaters containing high dissolved solids levels for selective reuse. Waters in this category are methanation condensate, boiler blowdown and gas liquor after treatment for organics removal.

- Wastewater Treatment. Effluents from by-product recovery operations and raw wastewaters not suitable for by-product recovery require treatment for the reduction of organic content (BOD, COD), suspended solids, reduced inorganic species (SCN^-, $S^=$, NH_3), toxic materials (e.g., heavy metals) and dissolved salts. The various wastewater treatment processes and their capabilities have been reviewed previously. The processes which are in use at the SASOL plant in South Africa and those which have been proposed for use in the commercial SNG facilities in the United States are listed in Table 4-21. These processes are generally those which have been widely employed in the treatment of municipal and industrial wastewaters and have proved to be economical and reliable. All wastewater management plans proposed for U.S. commercial gasification facilities are aimed at achieving zero discharge to surface waters. Accordingly, these plans do not incorporate the use of advanced wastewater treatment systems such as activated carbon adsorption, ion exchange and membrane processes for the removal of potentially troublesome organics and inorganic salts and for the reduction of total dissolved solids. The use of such processes may be required if the plant effluents are to be disposed of into natural waters, applied to soil, or used for certain in-plant uses.

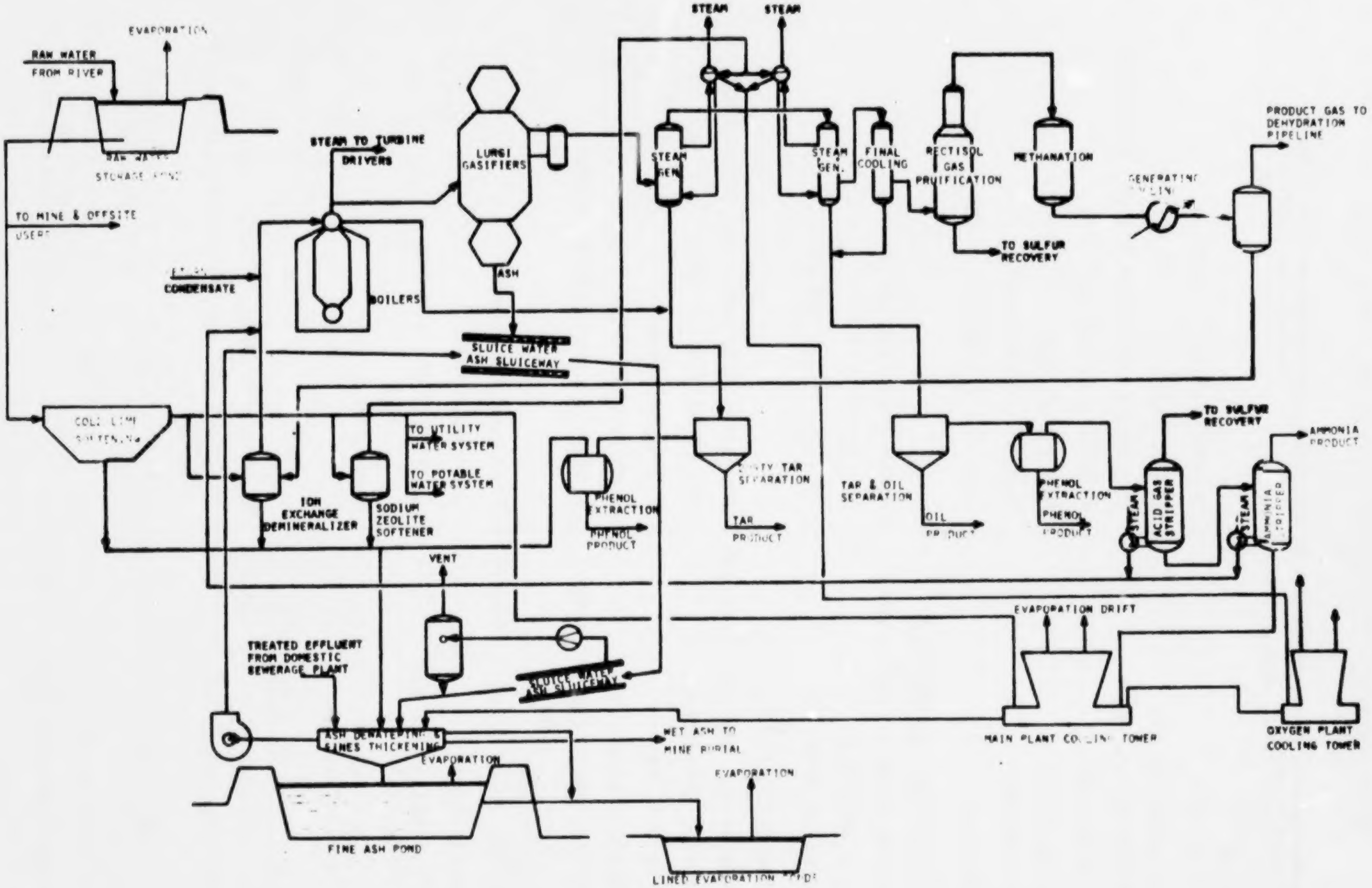

EVAPORATION
RAW WATER
FROM RIVER
RAW WATER
STORAGE POND
TO MINE & OFFSITE
USERS
CONDENSATE
STEAM TO TURBINE
DRIVERS
BOILERS
LURGI
GASIFIERS
ASH
SLUICE WATER
ASH SLUICEWAY
STEAM
STEAM
STEAM
GEN.
STEAM
GEN.
FINAL
COOLING
RECTISOL
GAS
PURIFICATION
METHANATION
TO SULFUR
RECOVERY
GENERATING
PRODUCT GAS TO
DEHYDRATION
PIPELINE
COLD LIME
SOFTENING
ION
EXCHANGE
DEMINERALIZER
SODIUM
ZEOLITE
SOFTENER
TO UTILITY
WATER SYSTEM
TO POTABLE
WATER SYSTEM
PHENOL
EXTRACTION
PHENOL
PRODUCT
DUSTY TAR
SEPARATION
TAR
PRODUCT
TAR & OIL
SEPARATION
OIL
PRODUCT
PHENOL
EXTRACTION
PHENOL
PRODUCT
STEAM
ACID GAS
STRIPPER
TO SULFUR
RECOVERY
STEAM
AMMONIA
STRIPPER
AMMONIA
PRODUCT
VENT
TREATED EFFLUENT
FROM DOMESTIC
SEWERAGE PLANT
SLUICE WATER
ASH SLUICEWAY
ASH DEWATERING &
FINES THICKENING
EVAPORATION
WET ASH TO
MINE BURIAL
FINE ASH POND
EVAPORATION
LINED EVAPORATION POND
EVAPORATION DRIFT
MAIN PLANT COOLING TOWER
OXYGEN PLANT
COOLING TOWER

Figure 4-5. Proposed El Paso Burnham Lurgi SNG Plant Water Management System(80)

TABLE 4-21. WASTEWATER TREATMENT PROCESSES USED AT THE SASOL LURGI PLANT AND THOSE PROPOSED FOR USE AT COMMERCIAL LURGI FACILITIES IN THE U.S.

Plant/Process	Wastewater Handled
SASOL Plant(44)	
API separation	Gas-oil refining condensate
Flocculation of oil	Petrochemical and oil refinery wastes
Trickling filtration	Combined plant and municipal wastewater
Sand filtration	Trickling filter effluent
Settling ponds	Ash quench water
Neutralization	Fischer-Tropsch acids
Drying beds	Digested biological sludge
El Paso (Burnham, New Mexico)(2)	
Oxidation tower (cooling tower)	Ammonia stripper bottoms
Gravity Settling	Ash quench water
Evaporation pond	Combined plant effluent
WESCO (New Mexico)(3)	
API separation and air flotation	Raw gas quench water and plant runoff waters
Biological treatment	Air flotation effluent
Gravity settling	Ash quench water
Evaporation pond	Combined effluent
Oxidation tower (cooling tower)	Biological treatment effluent
ANG (North Dakota)(15)	
Oxidation tower (cooling tower)	Stripped gas liquor
Evaporation/settling pond	Ash quench water
Multi-effect evaporator (distillation)	Cooling tower blowdown
Gravity oil separator with flocculation	Runoff waters
Wyoming Coal Gas Co. (Wyoming)(14)	
Oxidation tower (cooling tower)	Ammonia stripper bottoms
Gravity separation and flotation	Sanitary and runoff waters, ash quench waters
Multistage flash evaporation and ozonation	Portion of ammonia strippers bottoms to be upgraded to boiler feed water
Brine evaporation	Cooling tower blowdown, raw water treatment brines, clarified ash quench water

- Water Reuse and Recycling and Good Housekeeping Practices. Most of the currently proposed commercial SNG facilities would be located in the western United States where water is relatively scarce and expensive. To avoid extensive add-on wastewater treatment which may be required as a result of possibly very stringent effluent limitation guidelines which may be established in the future, the wastewater management plans for proposed SNG facilities incorporate a zero discharge concept. To achieve the goal of zero effluent discharge and to minimize raw water requirements, proposed designs for these plants provide maximum reuse and recycling of the wastewaters. Examples of multiple water usage in these facilities are: use of boiler blowdown, steam and knockout drum condensates and ammonia stripper bottoms as cooling water makeup; use of methanation condensates for boiler feedwater; use of cooling tower blowdown and raw water softening brines as ash quench water makeup; recycling of the settled raw gas quench water to the quench tower; recycling of the settled ash quench tower blowdown to the ash transport systems; and treatment of waste brine by distillation and use of the distillate as boiler feed water. That portion of the wastewater not reused and recycled would either be disposed of with waste solids or lost as vapor in the cooling tower or from the evaporation pond. To minimize water wastage and wastewater generation, it is essential that good housekeeping and water conservation measures be incorporated in the design of integrated facilities and be observed during the operation of such plants. Such measures may include elimination of leaks, routine equipment maintenance and personnel education.

- Ultimate Disposal of Treated Wastewaters. Although good water management at Lurgi SNG facilities can minimize both the raw water requirement and the amount of aqueous wastes generated, there will be some quantity of final effluent which requires ultimate disposal. To date, all proposed Lurgi SNG plants are to be located in relatively dry areas where raw water is expensive. This high cost of water plus the uncertainty about future discharge restrictions which may be imposed on SNG facilities has prompted designers to propose "zero" discharge to surface waters. In the southwest (New Mexico), the use of evaporation ponds is entirely feasible to meet this goal since climate is favorable and land is available and relatively inexpensive.

Ponds for temporary or permanent retention of raw or treated wastewaters (and sludges) are widely used for disposal of industrial and municipal wastewaters. These ponds, which are referred to as "evaporation ponds," "holding basins," "lagoons," "oxidation ponds," "settling basins," etc. are usually natural or man-made earthen reservoirs into which wastewaters are discharged. These ponds may be lined with impermeable materials (plastic, clay, asphalt, etc.) to prevent infiltration of the contents into the surroundings. Although liners have been used for industrial waste ponds, the ability of a liner to retain its integrity over long periods of time has not been established. The retention of the wastewater in the pond provides for natural evaporation, settling of solids, biological decomposition of organics and loss of the more volatile components of the waste. In geographic regions where annual evaporation exceeds precipitation, the ponds are generally designed to have no effluent discharge. Ponds can also be used for temporary waste storage and controlled discharge during high flows in the receiving waters. Evaporation/retention ponds require minimum maintenance and when large land areas are available, can be the most economical method for wastewater disposal. The SASOL gasification complex in South Africa uses a settling pond for polishing treatment of the total plant effluent before discharge into a river. Ponds are also used at all U.S. coal gasification pilot plants and have been featured in all proposed designs for commercial SNG facilities in the U.S. Because of solids accumulation, provisions must be made for periodic removal and disposal of solids from ponds and/or for ultimate decommissioning of ponds. Costs of evaporation ponds vary considerably depending on pond area, land costs, depth and lining requirements.

In the Northern Great Plains and the eastern U.S. where climatic conditions do not allow for sufficient evaporation, use of ponds alone is not feasible for ultimate wastewater disposal. The proposed designs for the Wyoming and ANG facilities feature forced evaporation for ultimate disposal of wastewaters and deep well injection and mine disposal for handling brines/sludges. Fored evaporation (multi-effector brine concentrators) is one of several processes which are commercially available or are under development for the removal of dissolved solids from wastewaters. Other processes include ion exchange, reverse osmosis, electrodialysis, freezing and electrochemical treatment. These processes are in varying stages of development and only the first four mentioned are given serious consideration as practical processes for large scale application. Key features of the dissolved solids removal processes are listed in Table 4-22. As noted in the table, the ion exchange and membrane processes (reverse osmosis and electrodialysis) are subject to fouling by organics. Accordingly, the applicability of these processes for wastewater processing would be limited to effluent polishing and to wastewaters containing very low levels of organics. For large scale applications, these processes would tend to be energy intensive. The quality of suspended solids in the influent of ion exchange, reverse osmosis and electrodialysis processes significantly effects the operating efficiencies of these processes. Plugging occurs especially in the membrane processes (electrodialysis and reverse osmosis) which lowers the processes efficiencies. Therefore, the influents to these processes should be filtered for optimum performance. Carbon adsorption may also be necessary prior to use of membrane processes for organics removal. Unlike processes which require feed pretreatment, the influent to the forced evaporation systems does not require filtration for the removal of organics (influent may require caustic addition to suppress the volatility of phenols and organic acids). However, as shown in the table, forced evaporation has the highest energy requirements of the dissolved solids removal processes. The energy for forced evaporation may partially be supplied by low grade heat sources within the plant, such as steam from waste heat recovery during primary cooling and discarded steam from the steam compressors used in final SNG compression.

Costs associated with dissolved solids removal processes depend heavily upon feed and effluent TDS levels, flow rate and the cost of energy. Generally, costs for ion exchange, reverse osmosis and electrodialysis are in the range of \$0.1 to \$0.25 per 1000 ℓ (\$0.4 to \$1.0 per 1000 gal) of feed in 1976 dollars, while costs for evaporation are estimated at around \$1/1000 ℓ (\$4/1000 gals)(76). (These costs do not include residue handling and disposal.)

An alternative to ponding or discharge to surface waters for ultimate wastewater disposal is deep well injection. This method of disposal has been used for a number of years in the geothermal and oil fields for reinjection of fluids and by a number of industries for the disposal of a range of concentrated wastes. The design of the proposed ANG Lurgi commercial plant features deep well injection for the disposal of raw water treatment brines. Deep well injection can only be practiced in areas where suitable underground geological formations exist and where there is very little potential for the contamination of usable groundwaters.

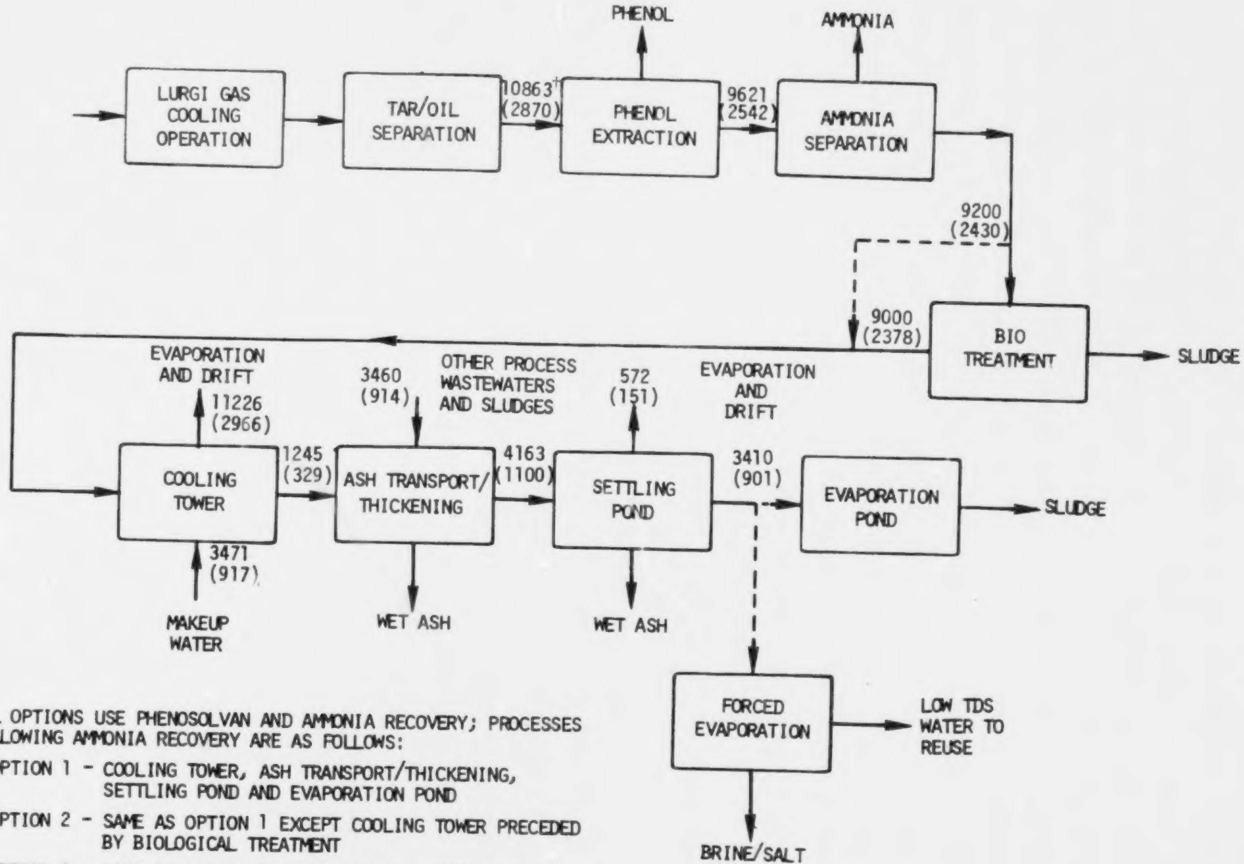
TABLE 4-22. FEATURES OF DISSOLVED SOLIDS REMOVAL PROCESSES

Process	Operating Principle	Major Existing Application	Advantages	Disadvantages	Energy Req.	TDS of Effluent	Water Recoverability
Ion Exchange	Exchange of nonobjectionable ions (e.g., H^+, OH^-) with objectionable species (e.g., Ca^{+2}, Mg^{+2}, F^-); resins are regenerated with acids, bases or salt solutions	Water softening, boiler water treatment, purification of chemicals, material recovery	Efficient and reliable process; can be automated; relatively low operating cost	Generates waste brine; most resins subject to fouling by organics	Direct requirements are low	0.5 to 30% of influent	essentially 100 %
Reverse Osmosis	Use of semi-permeable membranes and application of pressure to separate water from dissolved constituents	Demineralization of brackish waters; purification of industrial chemicals and pharmaceuticals: material recovery	Removal of most wastewater components in a single operation	Generates a concentrated waste; membrane subject to fouling and degradation; relatively high energy requirements	2.4-2.9 kwh/liter (9-11 kwh/1000 gal of feed	50-100 mg/l	About 80 %
Electrodialysis	Use of anion- and cation-permeable membranes and an electric field to effect separation of mineral ions from water	Industrial applications; pilot scale testing for wastewater treatment	Efficient separation of minerals from water	Generates a concentrated waste; membranes subject to organic fouling; limited experience with wastewater treatment	.05-0.1 kwh/1000 l (0.2-0.4 kwh/1000 gal) for each 1000 mg/l TDS removed plus 0.5-0.8 kwh/1000 l (2-3 kwh/1000 gal) for pumping	< 1000mg/l	50 - 90 %
Evaporation (Multi-effect evaporators or or brine concentrators)	Application of heat to evaporate water for recovery	Brackish and sea water desalinization; industrial wastewater treatment	Recovered water low in TDS high solids content of brine solution of salt cake requiring disposal	Generates a waste brine; scaling problem; high energy requirement: some volatile substances may appear in the distillate	18-24 kwh/1000 l (70-90 kwh/1000 gals) in the form of heat	< 10 mg/l	90-98 %

A suitable geological formation is one that: (1) is sufficiently large in capacity (area, depth and porosity) to accommodate large volumes of wastes at a reasonable injection pressure (2) does not contain brine or minerals of commercial value, (3) is located below the lowest groundwater zone and (4) is isolated above and below by impervious layers and contains no extensive faults or fractures of formations to assure that the injected waste would remain within the disposal strata. The liquid waste to be injected must be physically and chemically compatible with the formation. Wastes containing significant concentrations of suspended solids or constituents which may result in the formation of precipitates and plugging of the pores in the disposal stratum require pretreatment (e.g., sedimentation, pH adjustment, filtration, etc.) prior to injection. Well construction should provide adequate protection against groundwater contamination and should include provisions for continuous monitoring of well performance and movement of the waste underground, including continuous sampling of subsurface water courses by monitor wells. In the event of system failure due to the failure of the well casing, the casing would have to be replaced or the well may have to be sealed (packed and grouted) and abandoned.

Estimates of the cost for new deep well disposal systems should be made on a case-by-case basis and require a detailed knowledge of the subsurface geology and physical and chemical characteristics of the waste. A 1961 survey(92) indicated that the total costs of underground waste injection systems ranged from $30,000 (for a system without surface equipment for pretreatment of the waste) to $1,400,000 for one with elaborate equipment and a well 3660 meters (12,000 feet) deep. The average cost was $200,000. The operating cost for deep well injection is dependent on the pretreatment requirements and the operating pressure at the well head. The well pressures reported for existing facilities range from below atmospheric to over 7 MPa (1000 psia).

- Costs and Energy Requirements for Wastewater Treatment. Figure 4-6 presents a flow diagram for wastewater treatment at a Lurgi SNG facility, based on by-product recovery and treatment processes which have been featured in designs for proposed commercial Lurgi SNG plants. Depending on whether the effluent from the ammonia recovery unit is used directly as cooling tower makeup or is treated first by biological oxidation prior to such use and on whether solar or forced evaporation is used for ultimate disposal of the wastewater, four


PHENOL
AMMONIA
LURGI GAS COOLING OPERATION
TAR/OIL SEPARATION
10863†
(2870)
PHENOL EXTRACTION
9621
(2542)
AMMONIA SEPARATION
9200
(2430)
9000
(2378)
BIO TREATMENT
SLUDGE
EVAPORATION AND DRIFT
11226
(2966)
3460
(914)
OTHER PROCESS WASTEWATERS AND SLUDGES
572
(151)
EVAPORATION AND DRIFT
COOLING TOWER
1245
(329)
ASH TRANSPORT/ THICKENING
4163
(1100)
SETTLING POND
3410
(901)
EVAPORATION POND
SLUDGE
3471
(917)
MAKEUP WATER
WET ASH
WET ASH
FORCED EVAPORATION
LOW TDS WATER TO REUSE
BRINE/SALT

*ALL OPTIONS USE PHENOSOLVAN AND AMMONIA RECOVERY; PROCESSES FOLLOWING AMMONIA RECOVERY ARE AS FOLLOWS:

OPTION 1 - COOLING TOWER, ASH TRANSPORT/THICKENING, SETTLING POND AND EVAPORATION POND

OPTION 2 - SAME AS OPTION 1 EXCEPT COOLING TOWER PRECEDED BY BIOLOGICAL TREATMENT

OPTION 3 - SAME AS OPTION 1 EXCEPT USE OF FORCED EVAPORATION IN PLACE OF EVAPORATION POND

OPTION 4 - SAME AS OPTION 2 EXCEPT USE OF FORCED EVAPORATION IN PLACE OF EVAPORATION POND

†ALL FLOWS ARE IN L/MIN (GAL/MIN) AND HAVE BEEN DERIVED FROM THE DESIGN FOR THE EL PASO LURGI SNG FACILITY

Figure 4-6. Wastewater Treatment Alternatives for Lurgi SNG Systems*

treatments are identified. A breakdown of the estimated capital and operating costs for the four alternative treatment systems is presented in Table 4-23. The cost estimates indicate the following for the specific process conditions and unit costs assumed:

(a) The largest capital and operating cost items are those for the Phenosolvan process; the value of the recovered phenol only partially offsets the process cost.

(b) The relatively high cost of ammonia recovery is more than offset by the value of the recovered ammonia.

(c) Biological treatment is a high cost item. The requirement for biological treatment is not established at this time; if the raw wastewater can be used directly as cooling tower makeup (i.e., as in Options 1 and 3), the use of biological treatment ahead of the cooling tower may not be necessary. This would result in a savings of about 40% in total annual cost.

(d) Evaporation ponds require a much larger capital investment than forced evaporation. Due to higher operating cost, the estimated total annual cost for forced evaporation is somewhat higher than for an evaporation pond.

(e) For the four options considered, the total capital cost for wastewater treatment accounts for about 1 to 1.5% of the estimated total plant investment of about $2 billion; the total annual cost is about 0.5 to 1% of the total plant annual cost.

4.4 SOLID WASTE MANAGEMENT ALTERNATIVES

Figure 4-7 identifies five solid process modules for treatment/ultimate disposal of solid wastes in a Lurgi SNG facility. These are resource recovery, incineration/fuel use, soil application, land burial/landfilling, and use of evaporation/retention ponds. A number of other methods, such as ocean disposal and deep well injection, have been and are being used for the disposal of municipal and certain industrial sludges. It is, however, very unlikely that these methods would be used for the disposal of sludges from commercial Lurgi SNG plants because of environmental regulations or geographic factors. The following subsections present a brief discussion of these process modules as applied to specific solid wastes and sludges generated in coal preparation, coal gasification, gas purification, gas upgrading operations and auxiliary processes. In addition, solid waste management options at integrated facilities are discussed.

TABLE 4-23. ESTIMATED CAPITAL AND OPERATING COSTS FOR WASTEWATER TREATMENT AT INTEGRATED LURGI SNG FACILITIES

Process	Cost for Commercial Lurgi SNG Facility					Annual Energy Requirement 10^9 kcal (10^9 Btu)
	Capital Cost (10^6 \$)	Amortized Capital Cost* (10^6 \$/yr)	Annual Operating Cost (10^6 \$/yr)	By-Product Credit (10^6 \$/yr)	Total Annual Cost (10^6 \$/yr)	
Phenosolvan†	11.44	1.96	2.22	[0.72]	3.46	346 (1382)
Ammonia recovery‡	6.53	1.11	3.82	[6.97]	[2.05]	520 (2081)
Biological treatment§	9.9	1.49	0.44	--	1.93	27 (109)
Fine ash thickening#	0.84	0.12	0.056	--	0.176	0.2 (0.7)
Forced evaporation**	3.5	0.59	1.14	--	1.73	141 (565)
Evaporation pond††	9.6	1.4	--	--	1.4	--
Totals‡‡						
Option 1	28.41	4.06	5.84	[7.69]	2.21	866 (3463)
Option 2	38.31	5.43	6.28	[7.69]	4.02	892 (3572)
Option 3	22.31	3.19	6.98	[7.69]	2.38	1007 (4028)
Option 4	32.21	4.60	7.42	[7.69]	4.33	1034 (4137)

*Amortization at 15%/year.

†Costs based on benzene extraction; feed containing 1800 mg/l monohydric phenols and 1200 mg/l polyhydric phenols; 95% recovery monohydric phenols and 60% recovery polyhydric phenols; credit for crude phenol at 4.8¢/kg(76).

‡Ammonia recovery based on Phosam W process; feed containing 10,000 mg/l NH_3; recovery is 98%; credit for NH_3 at \$154/tonne(76).

§High purity oxygen/trickling filter system; influent characteristics: phenols - 570 mg/l (estimated BOD equivalent 1370 mg/l), fatty acids and other degradable organics - 1300 mg/l (estimated BOD equivalent 2000 mg/l); estimated BOD removal efficiency: 90%(73).

#Thickener solids loading assumed at 147 kg/m^2 day (30 lb/ft^2 day)(75).

**Based on cost and energy estimates in Reference 76.

††Assumes that 127 cm/year (50 in/year) of water can be evaporated for a pond surface or 1220 l/m^2/year (30 gal/ft^2/year). Excavation costs estimated at \$6.5/m^3 (\$0.185/ft^3)(90); pond linings cost \$4/m^2 (\$0.37/ft^2)(94). Land cost estimated at \$1500/hectare (\$500/acre). Pond is assumed to be 0.6 m (2 ft) deep.

‡‡See Figure 4-6 for flow diagrams.

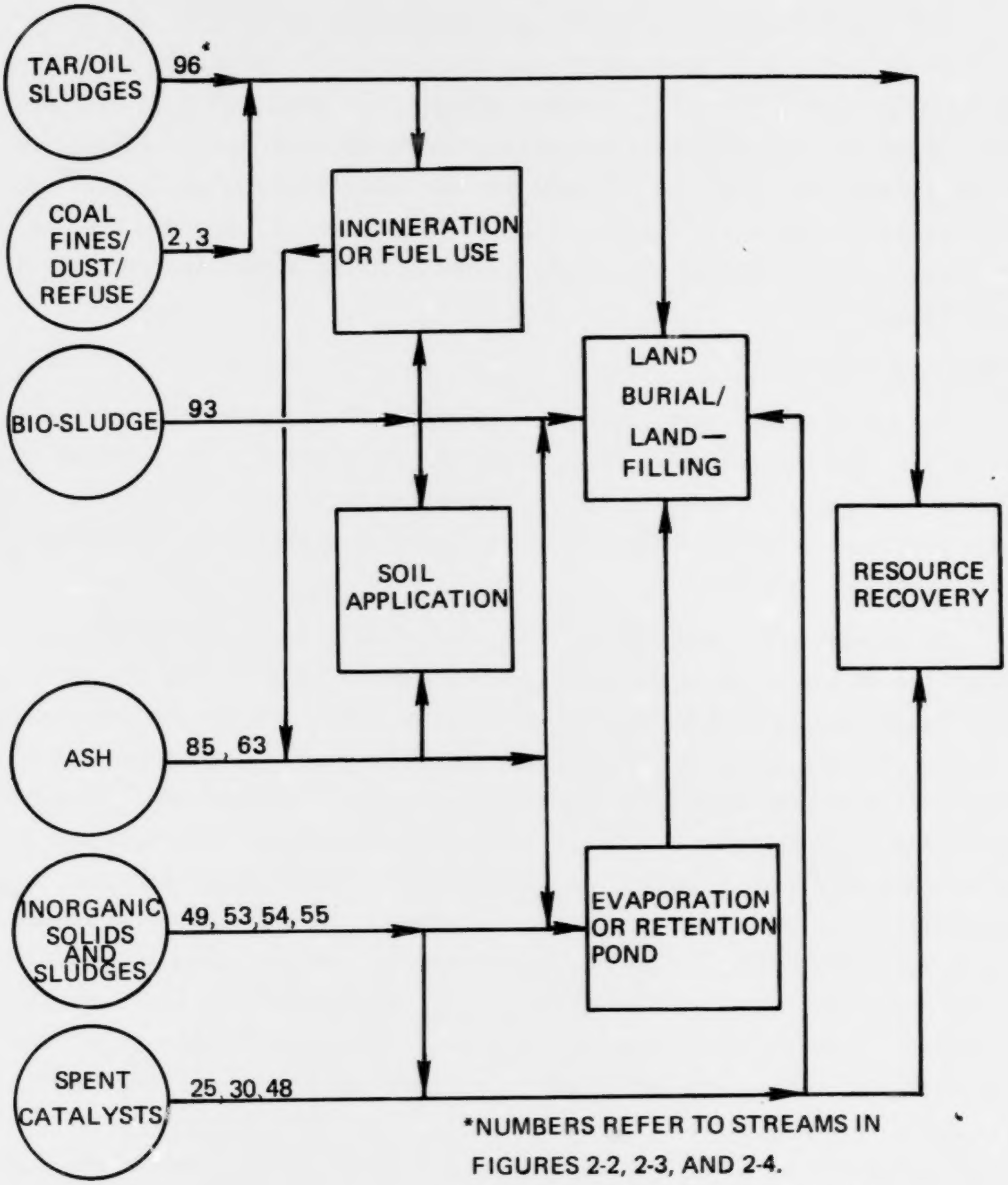

TAR/OIL SLUDGES
96*
COAL FINES/ DUST/ REFUSE
2, 3
BIO-SLUDGE
93
ASH
85, 63
INORGANIC SOLIDS AND SLUDGES
49, 53, 54, 55
SPENT CATALYSTS
25, 30, 48
INCINERATION OR FUEL USE
SOIL APPLICATION
LAND BURIAL/ LAND— FILLING
EVAPORATION OR RETENTION POND
RESOURCE RECOVERY
*NUMBERS REFER TO STREAMS IN FIGURES 2-2, 2-3, AND 2-4.

Figure 4-7. Process Module for Solid Waste Management in a Commercial Lurgi SNG Facility

4.4.1 Coal Pretreatment and Handling

Solid wastes generated during coal preparation consist of coal refuse, coal fines and dust. These wastes can be disposed of along with other plant solid wastes and by burial in surface mine(s) (see Section 4.4.2). Alternatively, such wastes may be hydraulically transported to settling ponds where solids would accumulate. (The use of ponds for the containment of wastewaters and sludges was discussed in Section 4.3.5.) Coal fines and dust may also be used in boilers, thus reducing the volume of the waste to a much smaller ash volume for disposal.

4.4.2 Coal Gasification

The Lurgi gasification operation generates an ash which is quenched with water and then hydraulically transported to ash thickeners and settling ponds. The bulk of the ash separates and is usually recovered as a wet sludge. The most practical disposal methods for this material would likely be burial in surface mines or landfills.

In conventional landfilling (i.e., use of sanitary landfills) the waste is deposited in layers on land, compacted and covered with a layer of dirt. Sanitary landfills are widely used for the disposal of municipal and industrial refuse. Co-disposal of biological wastewater treatment sludges and municipal refuse is also practiced at a number of landfills. Provided that adequate measures are taken to reduce potential for the contamination of ground and surface waters and to minimize the nuisance associated with landfill operation, sanitary landfilling can be an environmentally acceptable and cost-effective method for solid waste disposal. To minimize the potential for the contamination of groundwater and surface waters, landfills must be located in areas where the subsurface formation is relatively impervious to infiltration (e.g., dense clays) and where the distance to the groundwater table is significantly large. The landfill surface area should also be properly contoured to divert surface runoff from the site. When the subsurface formations do not provide adequate barriers against leachate infiltration, the use of artifical barriers such as plastic, asphalt, concrete or clay materials for lining the landfill may be necessary. The intercepted leachate would be pumped to a surface facility for treatment. Observation wells should also be installed downstream of the landfill site (in the direction of groundwater flow) to detect leachate migration. When the gasification plant is located at some distance from the coal mine and suitable land is available, conventional landfilling would likely be employed for the disposal of bulk or chemically fixed solid wastes and sludges.

When transportation costs are not excessive, return of the coal gasification solid wastes and sludges to the coal mines would be an attractive means for the disposal of such wastes, especially when area surface mining is practiced. The designs for all proposed commercial Lurgi SNG plants call for the return to surface mines of all plant solid wastes. Disposal in surface mines would essentially be one form of landfilling where the overburden material would be used as the cover material. The operation would be subject to the same restrictions cited above for sanitary landfills. When coal is mined by deep mining, there would be a greater time delay before the waste can be deposited in the mine. In the case of deep mining, the physical operation of returning the waste to the mine would also be more difficult, requiring certain changes in mine design and operation to accommodate the space and equipment for returning the wastes. The return of ash and flue gas desulfurization sludges to the mines would have the potential benefit of reducing acid mine drainage. This would especially be the case in eastern mines where acid mine drainage is a major pollution problem.

The costs of ash disposal by landfilling or return to mines are very plant-specific and are affected by the availability and cost of land; extent of landfill lining, leachate collection/treatment and monitoring required; transportation distance; and the extent that ash disposal is integrated with the total solid waste disposal plan for the plant, with the mine operation and with the surface mine reclamation program.

The total cost for landfill disposal of power plant fly ash and FGD sludges has been estimated at about \$12/tonne(95) (\$11/dry ton). The ash disposal cost for Lurgi plants located at the mine mouth (e.g., the proposed commercial plants) should probably be somewhat less because a portion of the cost would be incurred in the mine reclamation cost. The primary energy requirement for ash disposal by landfilling or return to mine is for the fuel used for waste haulage. The typical energy requirement for waste transportation by truck is approximately 4500 kcal/tonne-km (12,000 Btu/ton-mile), assuming that the trucks would return empty. When wastes are returned to mine, some fuel savings may be realized by utilizing coal haul trucks for hauling solid wastes to mines.

4.4.3 Gas Purification

Spent methanation guard is the only solid waste generated in the gas purification operation. Methods for the disposal of methanation guard are essentially the same as those discussed below for the management of gas upgrading wastes.

4.4.4 Gas Upgrading

Shift and methanation catalysts (and the methanation guard material) eventually become deactivated and require replacement or regeneration. For ZnO and most nickel-based methanation catalysts, onsite regeneration may not be practical or possible and hence, these materials must either be sent to metals/ catalyst vendors for recovery of metal values or disposed of as solid waste. In the case of cobalt molybdate shift catalyst, onsite regeneration by air oxidation to remove carbon, organics, and sulfur may be practical and hence reduce the spent catalyst disposal problem. Spent methanation catalysts, although deactivated as far as catalyst activity for methanation is concerned, still has a large capacity for adsorption of sulfur compounds and can be used as guard bed material. Because of the proprietary nature of most catalysts, little data are available on the economics of metal recovery from spent catalysts.

Since the guard and catalyst wastes contain high metals contents, carbonaceous materials (e.g., polycyclic organic material) and sulfur compounds, they may represent a hazardous material requiring special handling and disposal. Containerization or chemical fixation may be necessary before disposal in mines or landfills.

Chemical fixation (also referred to as cementation, waste passification or waste immobilization) has been used for the solidification of highly hazardous industrial wastes prior to disposal by landfilling or land burial. The objective of chemical fixation is to reduce solubility and chemical reactivity of the waste and hence reduce the potential for the contamination of ground and surface waters via leachate formation and runoff. Both organic and inorganic materials have been used as fixing agents. The fixing agents include asphalt, epoxies, tars, Portland and other lime-based cements, and proprietary formulations (e.g., in the Chem-fix process(96)). Raw or chemically fixed sludges can also be encapsulated in plastic, metal or concrete containers or coated with self-setting resins prior to disposal. Considerable effort is currently under way to establish the amenability of various wastes to chemical fixation and on the effectiveness of various chemical fixation processes to reduce the leachability of the waste. The chemical fixation processes are generally expensive and their applications limited to small-volume, high-toxicity wastes. Chemical fixation is estimated to add $1 to $3.70 to the cost of fly ash/FGD sludge disposal from power plants(95).

4.4.5 Auxiliary Processes

As discussed in Section 3.7.5, solid wastes associated with auxiliary processes are tarry and oily sludges from by-product storage and treatment of the runoff water; inorganic solids and sludges from raw water treatment and air and water pollution control processes; ash from coal-fired boilers; and biosludges from biological wastewater treatment processes. Processes for the control of each of these classes of solid wastes are reviewed in this section. In addition, a discussion of solid waste management at integrated facilities is presented.

Treatment and Disposal of Tarry and Oily Sludges. The tarry and oily sludges resulting from the treatment of plant runoff waters and the storage of by-products still contain a large amount of water (mostly in emulsified form) which may require removal prior to incineration or processing for by-product recovery. Emulsions can be "broken" by a number of methods including heating with or without chemical addition, precoat filtration, distillation, centrifugation and electrolytic coagulation. It is expected that some of these methods, particularly heat treatment and distillation, will find application in commercial Lurgi SNG facilities for the treatment of tarry/oily sludges. The performance and costs of these control processes are dependent to a large extent on the characteristics of the specific sludges handled. Since essentially no data are available on the quantities and characteristics of tarry/oily sludges from Lurgi SNG plants, the performance and costs of the control processes in Lurgi plant application cannot be determined at this time.

Tarry/oily sludges may be disposed of by landfilling alone or in connection with ash disposal. These types of wastes may also be incinerated or returned to the Lurgi gasifier(s) for destruction. Experience with refinery sludges indicates that a heating value of 4000 kcal/l (30,000 Btu/gal) is a minimum which will support combustion without supplemental fuel. Compared to land disposal methods, incineration requires very little space. Except for potential air pollution problems, which can be controlled by use of good design, afterburners, and particulate control devices, incineration is a most desirable disposal option (when resource recovery is inapplicable), especially for the destruction of hazardous organics. Major types of incinerators which are in commercial use are rotary kiln, multiple hearth furnace, fluidized bed and multiple chamber. Depending on the quantity and the heating value of the tarry and oily sludges, these sludges can be returned to the gasifiers. Some existing Lurgi plants feature injection of by-product tars and oils into the combustion zone of the gasifiers, and similar injection systems could probably be used for handling tarry/oily sludges.

Treatment of Inorganic Solids and Sludges. These wastes can be generated by raw water treatment, by air pollution control processes, and by water pollution control processes. Inorganic solids such as salts from evaporators may require fixation or containerization prior to disposal in mines or landfills to prevent leaching of soluble materials to groundwater. Relatively inert solids such as spent bauxite Claus catalyst may be combined with ash solids for disposal. Similarly, sludges such as those from raw water treatment and flue gas desulfurization units could be combined with ash quench slurry and sent to clarifying units for solids settling.

Inorganic solids and sludges can also be disposed of on land and incorporated into the top soil. Depending on the soil type, such materials can improve soil structure, reduce acidity, provide plant nutrients, and decrease the availability and hence toxicity of certain cations.

Control of Ash from Fuel-Fired Boilers. Bottom and fly ash from boilers is not greatly different in composition from gasifier ash, although particle size would be much smaller. Such ash can be transported to mines or landfilled either wet or dry. In the case of dry transport, care must be exercised to minimize fugitive ash dust emissions. In the case of wet transport, the disposal operation can be combined with gasifier ash disposal to reduce overall disposal costs.

Treatment and Disposal of Biosludges. Biosludges generated by wastewater treatment operations may be disposed of by incineration, landfilling, or soil application. Incineration has been successfully practiced for municipal and industrial biosludges for many years and is a reasonable alternative where land is not available for sludge disposal. Most sludges, however, are disposed of in conventional landfills and it is expected that Lurgi gasification biosludges would also be handled in a similar fashion. The sludge would be combined with ash and other solid wastes for burial in the mine or landfill (see Section 4.4.2).

Biosludges often require further treatment for concentration and volume reduction (dewatering) prior to disposal. Sludge dewatering is necessary to enable economic land disposal or incineration. Sludge concentration methods include gravity thickening, centrifugation, vacuum filtration, and use of filter presses and drying beds. These methods have been widely used in municipal and industrial wastewater treatment practice and considerable experience is available on them in a variety of applications. Table 4-24 presents reported data on solids concentration levels obtained by use of various sludge concentrating processes. Chemicals such as lime, ferric salts and synthetic organic polymers may be added to sludges to improve dewaterability. In general, biological sludges tend to be more difficult to dewater than inorganic sludges. Biological sludges and some concentrated organic wastes can also be further concentrated by use of anaerobic digestion whereby a portion of the organic material is converted to methane, carbon dioxide and soluble by-products. In addition to the reduction in sludge volume, anaerobic digestion improves sludge dewaterability and filterability.

TABLE 4-24. SOLIDS CONCENTRATION OBTAINED BY VARIOUS SLUDGE CONCENTRATING PROCESSES*

Process	Type of Sludge Processed	Solids Concentration Obtained (%)
Gravity thickening	Activated sludge	5 - 8
Centrifugation	Activated sludge	6 - 11
Vacuum filtration	Activated sludge	15 - 20
Drying beds	Primary and activated sludge	40

*The ranges of values reflect differences in sludge properties, system design and operating conditions. Results are obtained after 15 days of drying, for one specific application.

When large land areas are available and the climate (rainfall, evaporation) and hydrogeological conditions (distance to groundwater; groundwater flow, type of soil and geological formation) are favorable, some organic sludges may be disposed of by application to soil. The sludge is applied to the soil by "spreading" or "flooding," is disked under and worked into the top soil. The organic component of the sludge undergoes biodegradation in the soil and eventually becomes part of the soil humus. Sludge disposal by application to soils has been used for the disposal of biosludges from municipal sewage and refinery wastewater treatment plants. Land disposal of sludge can be used in conjunction with crop production or as part of a program for the reclamation/revegetation of lands disturbed by surface mining. As with the application of wastewaters to soils, sites for land disposal of sludges can present an odor problem or result in the contamination of surface waters and groundwaters, unless such sites are properly located, designed and operated.

Solid Waste Management at Integrated Facilities. In comparison with air and water pollution control, solid waste management options in an integrated commercial gasification facility are more limited and also more plant and site specific. The options for solid waste disposal are essentially limited to resource recovery, incineration and land disposal (soil application, landfilling, return to the mine and use of evaporation/retention ponds). Only a few of the wastes in a gasification facility (e.g., spent catalysts and methanation guards) lend themselves to resource recovery and it is very unlikely that this option would eliminate the bulk solid waste disposal requirement. The thermal destruction of wastes at an integrated gasification plant should be integrated with the design and operation of the gasifier and the utility boilers for onsite power generation to maximize energy recovery and minimize overall costs. The land disposal option is by far the most site-specific option and the selection of specific processes in this option would depend upon the plant location, transportation cost, hydrogeological conditions at the site and local environmental regulations. The solid waste management at an integrated plant is not an isolated problem but rather an element in the total program for pollution control. The choice of solid waste disposal methods is affected by the specific processes and options selected for air and water pollution control.

4.5 TOXIC SUBSTANCES CONTROL ALTERNATIVES

Based on the discussion in Chapter 3, toxic substances are or may be present in Lurgi product SNG, by-products and waste streams. The presence of toxic substances in product SNG and by-products (tars/oils, phenols and ammonia) can present occupational hazards and/or hazards to the general public due to end use and leaks and spills during transportation and handling. The use of proper operating procedures and effective industrial hygiene programs can minimize occupational hazards. The public health hazards which may stem from accidental spills and leaks in the plant or during handling or transportation can be minimized through strict adherence to safety and transportation regulations and prompt response to accidents. Many of the pollution control processes or practices discussed in Sections 4.2, 4.3 and 4.4 result in partial or nearly complete control of toxic substances in the waste streams. The following is a discussion of the controls for the toxic substances associated with Lurgi SNG systems.

4.5.1 Coal Pretreatment and Handling

Coal preparation can result in the generation of a certain amount of very fine coal dusts; by virtue of their fine size, such dusts can be considered toxic when inhaled. Most of the fine dusts are generated during crushing and screening; the particulate control device most suitable for the control of fine dusts from crushing and screening is the baghouse (see Section 4.2.1).

All coals contain trace elements which under certain conditions (e.g., formation of acids due to pyrite oxidation) may become solubilized and appear in leachate or runoff from coal piles and coal-selected solid wastes (e.g., coal refuse). The extent of solubilization and the volume of runoff produced would be coal- and site-specific. Generally, coal runoff control methods (e.g., containment, use as process water, etc.) would be effective in the control of toxic substances in the runoff. The leachate from the coal and refuse pile can be contained by use of liners underneath the piles and by collecting the leachate for treatment/reuse.

4.5.2 Coal Gasification

The only waste streams associated with coal gasification which may contain potentially toxic substances are the lockhopper vent gases, transient waste gases and the gasifier ash. The toxic components of the feed and ash lockhopper vent gases and of transient gases are CO, H_2S, COS, NH_3, HCN, CS_2, $Ni(CO)_4$, fine particulate matter, trace elements and low molecular weight aromatics. Incineration with particulate control, which would be used for the control of lockhopper and transient gases, should result in partial or total removal of these substances or their conversion to less toxic forms (e.g., conversion of H_2S to SO_2). No operating data are available on the degree of effectiveness of these methods for the control of toxic substances. The gasifier ash by itself should be a relatively non-toxic material. However, some trace elements present in the ash may become solubilized during hydraulic transport or in the landfill environment. Proper design and operation of lagoons and landfills can minimize potential for contamination of surface waters and groundwaters.

4.5.3 Gas Purification

Gas purification wastes and by-products containing potentially toxic substances are Rectisol acid gases, tars/oils, phenols, ammonia, clean gas liquor and spent methanation guard. The major toxic substances in the Rectisol acid gases are sulfur compounds, CO, HCN and aromatic hydrocarbons. The sulfur recovery and tail gas treatment processes are highly effective in removing or oxidizing these substances. Some Rectisol designs (e.g., that proposed for the El Paso plant) incorporate a special feature which significantly reduces the HCN loading to and the chemical losses in the downstream Stretford sulfur recovery unit. In these designs, HCN in the prewash flash gas is reabsorbed in water and sent to the shift reactor where it is converted to ammonia.

As with most crude petrochemical and industrial products, tars, oils, ammonia and phenols are or contain toxic substances which present occupational or public health hazards. Proper plant design and operating practices, adherance to safety and transportation regulations, effective industrial hygiene programs, good housekeeping practices and prompt response to accidents, which can be largely adapted from other industries, can reduce the hazards associated with the Lurgi by-products.

As noted in Section 3.6, the clean gas liquor contains a range of organic and inorganic constituents. Many of these constituents (e.g., $S^=$, SCN^-, aromatics, heavy metals) would ordinarily be classified as toxic substances. Certain of these toxic substances (e.g., pyridine) are not readily biodegradable and hence may not be totally removed when the clean gas liquor is treated by biological oxidation. Designs for the proposed commercial Lurgi SNG facilities call for the use of clean gas liquor as ash slurry makeup with subsequent control of the solid wastes which accumulate in ponds or which are disposed of in landfills. The control of toxic substances associated with methanation guards is discussed below in connection with control of toxic substances in gas upgrading wastes.

4.5.4 Gas Upgrading

The product SNG, spent shift and methanation catalysts (and methanation guard) and catalyst decommissioning/regeneration offgases are the major streams from gas upgrading operations which may contain potentially toxic substances. As noted in Chapter 3, these toxic substances include CO and $Ni(CO)_4$ in the SNG and in the decommissioning/regeneration offgases and metals and their inorganic and organic compounds and high molecular weight organics (possibly polycyclic compounds) in the spent catalyst. Through proper operating procedures, the amounts of CO and $Ni(CO)_4$ in SNG and in the catalyst decommissioning/regeneration off-gases can be minimized. In the case of the off-gases, further control can be achieved through incineration. When the spent catalysts are to be processed for resource recovery, care must be exercised in handling and transportation to reduce occupational hazards. Disposal of spent catalysts in landfills requires waste fixation/isolation and disposal site selection to minimize metal mobilization and hence environmental contamination.

4.5.5 Auxiliary Processes

Waste and by-product streams from auxiliary processes which contain potentially toxic substances are ash from onsite steam and power generation, evaporative emissions from by-product storage, tarry/oily and biosludges and inorganic solids and brines. The general control methods such as vapor recovery, recovery of sodium and vanadium salts from the Stretford purge, and landfill disposal of sludges and ash, which were discussed previously would also provide varying degrees of control for the toxic substances in these wastes. Because of the presence of toxic substances in these wastes, certain control modifications or extra precautions may be necessary in their handling and disposal. An example of such a change is encapsulation/chemical fixation of solids and sludges prior to land disposal. In some cases, use of a more expensive alternate disposal method may be necessary (e.g., incineration of organic sludges instead of land disposal).

4.6 SUMMARY OF MOST EFFECTIVE CONTROL ALTERNATIVES

4.6.1 Emissions Control

Table 4-25 summarizes the most effective commercially available methods for the control of various gaseous emissions in a Lurgi SNG plant, based on the detailed discussion in Section 4.2.

4.6.2 Effluents Control

Table 4-26 summarizes the most cost-effective methods for the control of various effluents in a Lurgi SNG plant, based on the detailed discussion in Section 4.3.

4.6.3 Solid Wastes Control

Table 4-27 summarizes the most cost-effective methods for the control of various effluents in a Lurgi SNG plant, based on the detailed discussion in Section 4.4.

4.6.4 Toxic Substances Control

Some of the emissions, effluents and solid wastes control methods listed in Tables 4-25, 4-26 and 4-27 are specifically aimed at the control of toxic substances in a waste stream. For example, the encapsulation/fixation of spent catalysts prior to disposal in landfills/mines is aimed at containment and immobilization of catalyst constituents. Other control methods listed in the tables, which are not specifically aimed at the control of toxic substances in various waste streams, do achieve varying degrees of control via containment, destruction or conversion of such substances to less hazardous forms. For example, incineration of sulfur recovery tail gases and catalyst regeneration/decommissioning off-gases results in the destruction of toxic substances such as CO, $Ni(CO)_4$, H_2S and aromatic hydrocarbons.

Since the product SNG and various by-products and waste streams in a Lurgi SNG facility would contain toxic substances which can present occupational exposure hazards to plant workers or public health hazards (e.g., resulting from spills/leakage during material handling and transportation or for end uses), Lurgi SNG plants must be designed and operated in a manner which would reduce

TABLE 4-25. MOST EFFECTIVE COMMERCIALLY AVAILABLE EMISSIONS CONTROLS

Operation/Process	Gaseous Waste Stream	Controls	Comments
Coal pretreatment and handling	Crushing and screening dusts	Dust suppression systems and baghouse	--
	Fugitive dusts	Dust suppression systems and enclosure of conveyors and transfer stations	--
Coal gasification	Feed lockhopper vent gas	Compression and recycle of pressurization gas and incineration of waste gas	Particulate control after incineration may be necessary
	Ash lockhopper vent gas	--	Particulate control would probably be necessary
	Transient waste gases	Incineration	Control of sulfur and particulate may also be necessary; insufficient data exists to establish control requirements
Gas purification	Rectisol acid gases	Stretford or ADIP/Claus processes	The control choice dependent on the sulfur content of the Rectisol gases; a combination of Stretford and ADIP/Claus may have the lowest overall costs
	Sulfur recovery tail gases (for additional sulfur recovery as HC/CO control)	Beavon and incineration or incineration and Wellman-Lord (or other FGD processes)	Incineration may be conducted in fuel-fired boilers to allow for heat recovery and a lower overall cost
Gas upgrading	Catalysts decommissioning/regeneration off-gas	Incineration	Waste stream characteristics not well established to determine additional controls (if any) needed
Auxiliary Processes	Depressurization and stripping gases	Treatment in combination with the Rectisol off-gases or incineration in fuel-fired boilers followed by flue gas desulfurization	Insufficient data available to determine the preferred control option
	By-product storage vent gases	Vapor recovery systems (for more volatile liquids) and use of floating roof storage tanks or conservation vents (for less volatile liquids)	--
	Steam and power generation flue gases	Electrostatic precipitation or fabric filters for particulate control; FGD systems using limestone, Wellman-Lord or dual alkali processes; use of desulfurized low Btu gas produced onsite as fuel for steam and power generation	The comparative economics of the FGD systmes have not been well established; the sulfur recovery tail gases may be incinerated in the fuel-fired boilers and the combined flue gas handled in the FGD system. Onsite production of fuel gas is generally more costly than direct coal/by-product combustion with pollution control, but results in lower overall emissions

TABLE 4-26. MOST EFFECTIVE EFFLUENTS CONTROLS

Operation/Process	Aqueous Waste Stream	Controls	Comments
Coal pretreatment and handling	Coal pile runoff	Diversion of runoff from adjacent areas; collection of runoff and treatment with other plant wastewaters	--
Coal gasification	Ash quench slurry	Bulk solids settling, fines thickening and storage/settling ponds	Other process wastes such as raw water treatment and air pollution control sludges and brines may be combined with the ash quench slurry for treatment and solids disposal
Gas purification	Raw gas liquor	Use of Lurgi tar/oil separator, Phenosolvan process and Phosam W process for tar/oil, phenols and ammonia recovery, respectively	Lurgi tar/oil separator and the Phenosolvan process are Lurgi-licensed and are featured in all designs for proposed commercial facilities
	Methanol/water still bottoms	Addition to dephenolized gas liquor prior to ammonia recovery	--
Gas upgrading	Methanation and dehydration condensates	Depressurization for dissolved gases removal and subsequent use as boiler feed water	--
Auxiliary Processes	Clean gas liquor	Use as cooling tower makeup with or without biological treatment	The need for and effectiveness of biological treatment of clean gas liquor not established
	Filter backwashes	Addition to ash quench slurry	--
	Waste sorbents and reagents	Recovery of reagents from air pollution control processes; addition to ash quench slurry; disposal by deep well injection	Deep well injection may not be practical at all sites
	Boiler blowdown	Use as cooling tower makeup	--
	Cooling tower blowdown	Use as ash quench makeup water	--
	Miscellaneous plant wastewaters	API separators and use of treated water as process water makeup (for plant runoff); use of packaged units for the treatment of sanitary wastewaters	--
	Overall (final) plant effluent	Solar or forced evaporation	Depending on the hydrogeological conditions, waste ponds may require lining; use of solar evaporation is dependent on regional/local climate

TABLE 4-27. MOST EFFECTIVE SOLID WASTES CONTROL

Operation/Process	Solid Waste Stream	Controls	Comments
Coal pretreatment and handling	Coal refuse, coal fines and dust	Use of coal fines as fuel; disposal in settling ponds and landfills	These wastes are not unique to Lurgi SNG plants and the controls are adaptable from other industries
Coal gasification	Wet ash	Disposal in landfills or return to mines	The quantity of ash accounts for more than 90% of the solid wastes generated at a Lurgi SNG plant. The choice and design of disposal system are dependent on the ash content of coal and plant/mine site characteristics.
Gas purification	Spent methanation guard	Fixation/encapsulation and disposal in landfills/mines; processing for metal recovery	The technical and economic feasibility of resource recovery have not been established
Gas upgrading	Spent shift and methanation catalyst	Processing for material recovery; use of spent methanation catalyst as methanation guard; fixation/encapsulation and disposal in landfills/mines	Data on the technology and economics of resource recovery processes have not been established
Auxiliary processes	Tarry/oily sludges	Disposal in landfills/mines with or without fixation/encapsulation; incineration; return to gasifier	Because of lack of data on waste quantities and characteristics, optimum control(s) cannot be established
	Biosludges	Disposal in landfills/mines, soil application, incineration	Because of lack of data on waste quantities and characteristics, optimum control(s) cannot be established
	Inorganic solids and sludges	Addition to ash quench slurry, direct disposal in landfills/mines	--
	Fly ash from steam/ power generation	Disposal in landfills or return to mines	--

worker exposure and potential for system upsets and equipment failure. Effective safety and industrial hygiene programs, strict adherence to safety standards and transportation regulations, and programs for quick response to emergencies are also necessary to reduce occupational and public health hazards.

4.7 MULTIMEDIA CONTROL SYSTEMS

There are several systems/approaches capable of achieving controls of waste streams to more than one medium in a Lurgi SNG plant. These systems/approaches fall into two general categories: (1) "in-plant" controls and (2) "end-of-pipe" controls. The "in-plant" controls include resource recovery, use of alternative processes/equipment and water reuse/recycling and good housekeeping practices. Some specific examples of in-plant controls are listed in Table 4-28.

Some of the end-of-pipe controls discussed in Sections 4.2, 4.3 and 4.4 achieve control of waste streams to more than one medium. Perhaps the best example of a multimedia end-of-pipe control is the use of lined settling/evaporation ponds for the containment/ultimate disposal of plant wastewaters. When properly designed and operated such ponds eliminate waste streams to surface waters and groundwaters, prevent land contamination (via percolation/seepage), and serve as a repository for particulate and dissolved solids contained in the waste streams.

While reducing or eliminating streams to specific media, some of the in-plant and the end-of-pipe multimedia controls generate new streams which would be discharged to the same or to different media. In most cases, however, the discharge problem is significantly reduced. For example, use of fuel gas instead of direct combustion for onsite production of steam and power generates Lurgi ash which would be easier to process and dispose of than the fly ash/FGD sludges produced as a result of the treatment of coal combustion flue gases. The technical and economic viability of the many multimedia control possibilities for Lurgi SNG facilities cannot be evaluated at this time due to the lack of an operating data base for integrated SNG plants.

4.8 REGIONAL CONSIDERATIONS AFFECTING SELECTION OF ALTERNATIVES

A number of regional (local) factors affect the selection of waste management processes/options at an integrated Lurgi SNG plant. Most important of

TABLE 4-28. IN-PLANT MULTIMEDIA CONTROL POSSIBILITIES FOR A LURGI SNG FACILITY

Category	Examples	Description
Resource recovery	Tar/oil recovery, phenol recovery, ammonia recovery, naphtha recovery, sulfur recovery, catalyst material recovery	Eliminates the recovered material from a waste stream and hence discharges to various media
Alternative process/ equipment	Use of fuel gas vs. direct coal/ by-product combustion	Eliminates the need for FGD/particulate control and hence discharges to air (SO_2, particulate), to land (FGD sludges/solids), and to water (leachate from solids disposed in landfills); system also allows for direct sulfur recovery
	Rectisol design to allow collection of HCN and recycling to shift converter for destruction	Eliminates emission of HCN to air (in the Rectisol off-gas) and to water (via Stretford blowdown or the gas liquor)
	Recompression and recycling of feed lockhopper pressurization gas	Eliminates emission to air and to water and land (from air pollution control systems)
Water reuse/recycling	Collection and treatment of coal and plant runoff waters for in-plant use	Eliminates land and water contamination and possibly emissions to air (when wastewaters contain volatile components)
Good housekeeping practices	Proper design, operation and maintenance of equipment to minimize process upsets, equipment failure and leaks/spills	Reduces emissions to all media

these factors are the type of coal processed, climate and hydrogeological conditions, and environmental regulations. Table 4-29 lists the general characteristics of the coals and the climate for six major "coal provinces" in the U.S. which, because of coal availability, are considered likely sites for the commercial SNG facilities. As noted in the table, both the coal characteristics and the climate vary with the province.

As discussed previously, the type of coal (specifically its sulfur moisture and ash content) determines the loadings to various by-product recovery/pollution control units (e.g., Rectisol and gas treatment and ash handling systems) and the volume and quantity of by-products recovered and sludges and solid wastes handled. These loadings, in turn, determine the size and cost of the process/pollution control equipment required and the choice and economics of the waste disposal options. For example, a 7 x 10^6 Nm^3/d (250 MMscf/d) Lurgi SNG plant processing a western coal (0.7% sulfur content) would produce Rectisol acid gases containing about 139 tonne/d (152 ton/d) of sulfur whereas a similar sized plant in the eastern U.S. handling an eastern coal (4% sulfur content) would produce Rectisol acid gases containing about 5.7 times as much sulfur.

In general, western coals tend to be higher in moisture content than the eastern coals. Lignites, for example, can contain up to 40% moisture whereas the moisture contents of the eastern coals are generally in the 5 to 10% range. The higher the moisture content, the larger would be the volume of the Lurgi gas liquor produced. The gasification of a subbituminous coal containing 17% moisture in a 7 x 10^6 Nm^3/d (250 MMscf/d) plant is estimated to generate 1.25 x 10^7 l/d (3.3 mgd) of gas liquor; in comparison, a similar size plant using a lignite coal with 38% moisture content would generate 2.4 x 10^7 l/d (6.3 mgd) of gas liquor. The large volume of gas liquor produced in the gasification of western coals coupled with the high cost of water in the coal provinces in the more arid west (EPA Regions VI and VIII), provides a strong incentive for treatment and in-plant use of the gas liquor in the western plants.

Although the ash content is not necessarily a regional characteristic of coal (coals from the same formation can vary widely in their ash content), ash content affects the quantity of solid wastes generated in an SNG plant and the choice and cost of solid waste disposal options.

TABLE 4-29. CANDIDATE REGIONS FOR LOCATION OF LURGI SNG FACILITIES (SELECTED FOR ANALYSIS IN THIS DOCUMENT)

Coal Province	States Within Province	EPA Region	Coal Characteristics	Climate Type
Eastern interior	Illinois Indiana W. Kentucky	IV, V	Bituminous, high sulfur, low moisture	Cold, wet
Eastern	Pennsylvania W. Virginia Ohio E. Kentucky	III, IV, V	Bituminous, medium/high sulfur, low moisture	Cold, wet
Gulf coast	Alabama Texas	IV, VI	Lignite, low sulfur, high moisture	Warm and wet to warm and semi-arid
Northeastern Great Plains	N. Dakota	VIII	Lignite, low sulfur, moderate to high moisture	Cold, dry
Northwestern Great Plains	Wyoming Montana	VIII	Subbituminous low sulfur, moderate moisture	Cold, dry
Rocky Mountains	New Mexico Colorado	VI, VIII	Subbituminous, low sulfur, moderate moisture	Warm and dry to cool and dry

The availability and cost of raw water and the hydrogeological conditions at the plant site have significant impacts on the choice of wastewater treatment processes and disposal options. As noted above, in the arid west (coal provinces in EPA Regions VI and VIII) where the water is less available and more expensive, there would be a stronger incentive to maximize water reuse within the plant than in the east where water is more abundant and less costly. As has been proposed in the designs for SNG plants to be located in EPA Region VI, such plants would use solar evaporation for ultimate disposal of the plant wastewaters; use of evaporation ponds would not be practical in wet climates (in EPA Regions III, IV, and V) and cold climates (EPA Region VIII) where annual evaporation may be only slightly more or less than the annual precipitation. Facilities located in such regions would have to use forced evaporation or processes such as reverse osmosis and ion exchange to treat a portion or all of the plant wastewaters.

To maintain the national ambient air quality standards and/or meet the prevention of significant deterioration criteria (PSD), air pollution control regulations may limit the size of Lurgi SNG plants or impose severe emissions restrictions on such plants. Compliance with more stringent regulations would increase pollution control requirements and costs.

4.9 SUMMARY OF COST AND ENERGY CONSIDERATIONS

Based on the cost and energy data presented in Sections 4.2, 4.3 and 4.4., the estimated total annual cost and energy requirements associated with air and water pollution control and solid waste management at a 7 x 10^6 Nm^3/d (250 MMscf/d) Lurgi SNG plant are as follows:

	Costs, $ million	Energy Requirement, 10^9 kcal/yr
Air pollution control	15 - 19	569 - 1560
Water pollution control	2.2 - 4.3	866 - 1034
Solid waste management	18 - 30*	2 - 7
Total	25.26 - 53.3	1437 - 2601

Based on the estimated total plant annual cost and energy input requirements of about $550 million and 3.6 x 10^{12} kcal, pollution control at an integrated plant would account for about 5 to 10% of the annual cost and 4 to 7% of the total energy input.

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*Based on a coal ash content range of 7 to 20%.

5.0 ANALYSIS OF REGULATORY REQUIREMENTS AND ENVIRONMENTAL IMPACTS

This section (a) reviews the standards and guidelines applicable to waste discharges to air, water and land media and to the toxic properties of marketed products, (b) compares the waste streams and products/by-products from Lurgi gasification systems with the applicable discharge and toxic substances control standards, (c) presents an analysis of the impacts of waste discharges from Lurgi gasification systems on the quality of the ambient air, water and land resources, (d) estimates the potential hazards associated with specific substances in products/by-products and waste streams which are not covered by existing regulations, and (e) discusses siting considerations for gasification plants. Before presenting an analysis of the regulatory requirements and environmental impacts associated with the Lurgi systems, a brief description of the environmental assessment methodologies, which are being developed by EPA for evaluating and comparing environmental impacts associated with the emerging fossil energy technologies, will follow.

5.1 ENVIRONMENTAL ASSESSMENT METHODOLOGIES

EPA's Industrial Environmental Research Laboratory, Research Triangle Park (IERL/RTP) has been working on the development of a standard set of methodologies for the environmental assessment* of fossil energy processes. Such standard methodologies are needed on a near-term basis to eliminate large gaps, inefficiencies and proliferation of techniques for evaluating and comparing environmental aspects of competing technologies and the effectiveness of various pollution control alternatives. The environmental assessment methodologies which are being developed by EPA represent prototype approaches to multimedia, multipollutant problem identification and control effectiveness evaluation for complex effluents. They are prototypes of potential future regulatory approaches that can handle the whole problem and are aimed at preventing problems before they occur. Hopefully they will allow resolution of existing problems on other than a one-pollutant-at-a-time basis, a basis which is fraught with endless studies, only partially effective results, and high costs at all levels of implementation.

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*As defined for IERL/RTP studies of fossil energy processes, an environmental assessment is a continuing iterative study aimed at: (a) determining comprehensive multimedia environmental loadings and environmental control costs, from the application of existing and best future definable sets of control/disposal options, to a particular set of sources, processes, or industries; and (b) comparing the nature of these loadings with existing standards, estimated multimedia environmental goals, and bioassay specifications as a basis for prioritization of problems/control needs and for judgment of environmental effectiveness.

The environmental assessment methodologies which are being addressed by EPA are currently in different stages of development with most of the work being carried out by contractors working under the direction of the EPA. These methodologies pertain to "current process technology background," "environmental data acquisition," "current environmental background," "environmental objectives development" (multimedia environmental goals), "control technology assessment," and "environmental alternatives analysis" (source assessment models). A flow/decision sequence diagram indicating how these specific methodologies and their outputs will be used by EPA in its environmental assessment/control technology development effort and a summary of the methodologies are presented in Figure C-1 and Table C-1 (Appendix C), respectively. A more detailed description of two of the methodologies (multimedia environmental goals and source assessment models) and a brief description of another methodology ("bioassay interpretation") which is also being developed by EPA for formatting/interpretation of bioassay data in connection with "current technology background" and "environmental data acquisition" efforts will follow.

5.1.1 Multimedia Environmental Goals

To establish a systematic means for the prioritization of the many chemical substances which are present in complex effluents for the purpose of environmental assessment and definition of control technology needs, EPA has established "Multimedia Environmental Goals" (MEG's) which are:

> ...Levels of significant contaminants or degradents (in ambient air, water, or land or in emissions or effluents conveyed to the ambient media) that are judged to be (a) appropriate for preventing certain negative effects in the surrounding populations or ecosystems, or (b) representative of the control limits achievable through technology(93).

To date a total of 650 chemical substances and physical agents (e.g., noise, heat), nearly all of which are expected to be associated with fossil fuel processes, have been selected as part of a "Master List" for which MEG's are to be established. The MEG's have already been established for 210 substances on the Master List. The MEG value(s) for a given substance may be based on several or all of the 12 criteria shown as headings for the MEG's chart in Table 5-1. These criteria cover emission level and ambient level goals. Depending on the data available, up to 12 MEG values may be generated for a given substance for each medium (air, water and land). One of the MEG criteria which is most currently used in environmental assessment work is the minimum acute toxicity effluent (MATE). MATE is the approximate concentration for contaminants in source emissions which will not evoke significant harmful or irreversible responses in exposed humans or ecology, when those exposures are limited to short durations (less than 8 hours per day).

Most of the MEG's are derived through models which translate toxicological data, recommended concentration levels, and federal standards or criteria into emission or ambient level goals. For most of the categories listed in Table 5-1, more than one model is available for obtaining the "estimated permissible concentration" (EPC). Where different EPC values can be obtained by using different models, the strictest is chosen as the MEG value. An example of a model which translates LD_{50}* (oral, rat) into the toxicity-based ambient level goal for air for the health effects category is:

$$\text{EPC in } \mu g/m^3 = 0.107\ LD_{50} \text{ (in mg/kg)}$$

This particular model was developed by Handy and Schindler(99) based upon the correlation between the reported LD_{50} (oral, rat) and TLV† for 241 substances, with adjustment made for continuous exposure using a factor of $\frac{40 \text{ (hrs per work week)}}{168 \text{ (hrs per week)}}$.

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*LD_{50}, Lethal dose fifty: the dose which when administered to a group of animals is lethal to one-half of the population. The mode of administering the dose and the test animal must be specified.

†TLV, Threshold Limit Value: levels of contaminants considered safe for workroom atmosphere, as established by the American Conference of Governmental Industrial Hygienists.

TABLE 5-1. CURRENT VERSION OF THE MEG'S CHART(98)

	EMISSION LEVEL GOALS						
	I. Based on Best Technology		II. Based on Ambient Factors				
Category	A. Existing Standards	B. Developing Technology	A. Minimum Acute Toxicity Effluent		B. Ambient Level Goal*		C. Elimination of Discharge
	NSPS, BPT, BAT	Engineering Estimates (R&D Goals)	Based on Health Effects	Based on Ecological Effects	Based on Health Effects	Based on Ecological Effects	Natural Background*
Air, µg/m^3 (ppm Vol)							
Water, µg/l (ppm Wt)							
Land, µg/g (ppm Wt)							

*To be multiplied by dilution factor

	AMBIENT LEVEL GOALS				
	I. Current or Proposed Ambient Standards or Criteria		II. Toxicity Based Estimated Permissible Concentration		III. Zero Threshold Pollutants Estimated Permissible Concentration
	A. Based on Health Effects	B. Based on Ecological Effects	A. Based on Health Effects	B. Based on Ecological Effects	Based on Health Effects
Air, µg/m^3 (ppm Vol)					
Water, µg/l (ppm Wt)					
Land, µg/g (ppm Wt)					

As part of the methodology for evaluating the toxicity of the substances on the "MEG Master List," EPA has developed a "hazard indicator" system which assigns indicators (x = hazardous, xx = very hazardous, xxx = most hazardous, N.H. = non-hazardous) to the substances. The system provides one simple means of identifying through cursory inspection those pollutants most likely to pose a human health hazard. Numerical values which provide the basis for assigning hazard indicators are obtained by using an equation which considers toxic and genotoxic potentials as well as cumulative or chronic effect characteristics.

As noted above, to date MEG values have been established for only 210 of the 650 substances on the "MEG Master List." Work is currently in progress to establish values for other substances on the list, to refine the models used for calculating MEG values and to update/revise the input to the MEG models. MEG Methodology has already found considerable application in environmental assessment work. For example, in the "phased approach" to sampling and analysis of process/waste streams, comparison of the pollutant levels with MATE values provide a basis for deciding whether or not to proceed to more detailed or sophisticated levels of sampling and analysis. As will be discussed in Section 5.1.2, MEG values are used in the "Source Analysis Models" for "screening" effluent streams. Tables C-2 and C-3 (Appendix C) present the MEG "chart" and background information summary, respectively, which have been developed for naphthalene.

5.1.2 Source Analysis Models (SAM's)

To fulfill part of the EPA's goal to develop control technology and perform environmental assessments for both energy and industrial processes, the EPA has created set of source analysis models (SAM's), which provide systematic methods of comparing the environmental effectiveness of pollution control options. The various members of the set of SAM's provide rapid screening, intermediate, or detailed approaches to relate effluent stream pollutant emission levels to the MEG's.

The simplest SAM, designated SAM/IA, will ordinarily be used for rapid screening of the difference between an uncontrolled process and the results of the application of various control options. This model compares either the sample fractions or specific pollutant species in the individual effluent stream, whichever data are available, to the MATE goals. The calculation of numerical values expressing the effectiveness of control options proceeds as follows. The ratio of the pollutant concentration to the MATE value (which may be based on either health or ecological effects) is called the "potential degree of hazard" (H). A quantity called the "potential toxic unit discharge rate" (PTUDR) is arrived at by multiplying H by the stream flow rate. Then the PTUDR's are summed over each medium (air, water and land) for each control option considered. Comparison of the PTUDR's calculated for each option shows (1) how the distribution of overall toxicity is influenced by choice of control options, and (2) which option allows the minimum discharge of overall toxicity to all media.

Use of the SAM/IA methodology for rapid screening requires making the following assumptions:

(a) The approximately 650 substances currently in the MEG list as potential components of an effluent stream are the only ones which need to be included at this time.

(b) Dispersion of effluents will be adequate and will offset any transformation to more toxic substances.

(c) The MATE values (or the basic data from which they were developed) are adequate.

(d) No synergistic effects occur.

The SAM/IA methodology is detailed in Reference 100. SAM/IB, which is currently under development, is an extension of the SAM/IA model incorporating bioassay test protocols.

The next of the source assessment model series, SAM/I, takes into consideration the factors mentioned in items (b), (c) and (d) above by applying "effluent transport/transformation analysis"* to the effluent stream constituents. The resultant ambient concentrations are compared with the MEG of choice, which may be based on best technology (BT), existing ambient standards (ES), standards based on prevention of significant deterioration (SD), estimated permissible concentration (EPC) or natural background concentration (NC). The remaining steps are similar to SAM/IA. The extended SAM/I considers urban and rural population densities and includes background ambient concentrations in the screening analysis. The SAM/I draft is now complete and is in review.

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*The SAM/I effluent transport/transformation analysis incorporates a simple dispersion model utilizing the Turner handbook (101), and elementary transformation considerations.

The most detailed source assessment model, SAM/II, is still in the planning stages. Calculations will be based upon ambient rather than on effluent concentrations. The transport/transformation models will be more rigorous than that used in SAM/I.

A SAM/IA summary sheet is presented as Table C-4 in Appendix C.

5.1.3 Bioassay Interpretations(102)

EPA/IERL is currently developing a methodology for reducing and formatting bioassay data generated as a result of extensive environmental data acquisition efforts using the phased approach to performing environmental source assessments. The phased approach requires three separate levels of sampling and analytical effort (see Table C-1 in Appendix C). Most of the bioassay to date has been in connection with Level 1 sampling and analysis which is designed to (1) provide preliminary environmental assessment data, (2) identify problem areas, and (3) generate data needed for the prioritization of energy and industrial processes, streams within a process, and components within a stream for further consideration in the overall assessment. The biological effects which are examined in Level 1 are primarily physiological, ecological, genetic or behavioral.

Development of a methodology for reducing and formatting bioassay data is being carried out under EPA contracts to Research Triangle Institute, Research Triangle Park, N.C., and Litton Bionetics, Kensington, MD. EPA has established the Bioassay Subcommittee of the Environmental Assessment Steering Committee to monitor and coordinate the methodology development effort(103).

The objectives of the EPA bioassay interpretations methodology development are as follows:

- Reduction and formatting of bioassay data into simple form
- Presentation of the results of bioassays in a form useful to chemists and engineers in the technologies
- Reduction of the data to a matrix which will "weight" the observed effects in terms of significant differences between exposed experimental organisms and their controls
- Publication of the methodology in a manual which will enable uniformity of assessment of the pollution potential of the source.

Development of a methodology for handling bioassay data is necessary because of the complex and specialized information resulting from bioassay sampling and analysis. Reducing and formatting the data are particularly important because the information must be used by chemists and engineers who may not be familiar with bioassay techniques but are required to use bioassay test results as the basis for design and operation of plants to conform with applicable environmental regulations.

The test matrix in Table 5-2 is an example of the minimal bioassay protocol which will be followed in order to investigate emissions which may have a high pollution potential. The large amount of information which must be gathered in order to produce a credible bioassay requires carefully planned collation and treatment(102).

In general, dose/response models are used for defining numerical or "weighted" relationships between toxic materials and their effect on test organisms. These ratings, which are designed to give an indication of the relative toxicities of effluents, are subject to some of the intrinsic difficulties associated with dose/response models. However, dose/response models can be extremely valuable tools for assessing the toxicity of effluents when presented by the methodology being developed. A brief description of dose/response models follows.

The basis of most dose/response models is derived from biological effects data obtained in the laboratory. In order for these models to be useful in estimating health/ecological effects, it is necessary to extrapolate effects observed in the laboratory into an unknown area. This extension of knowledge assumes a continuity, similarity, or other parallelism between the two situations. Often biological effects need to be extrapolated from (1) laboratory to field - many differences make this difficult; (2) one species to another - no two species are alike; (3) one medium to another - ingestion is not the same as inhalation; and (4) one life state to another - ranges of sensitivity may differ by orders of magnitude. In the present state of the art, biological effects data are collected from a few life states of a few species for a few routes of entry in a few controlled conditions. On the other hand, the real world situation contains thousands of species in many stages of growth, all of which may be continuously exposed to various types of doses.

TABLE 5-2. BIOASSAY TEST MATRIX*

Sample Type	Mandatory Test	Recommended Test	Optional Test
Liquids (aqueous)	Ames mutagenicity CHO cytotoxicity Whole animal (rodent acute) toxicity Freshwater or marine aquatic‡	--†	Additional cytotoxicity Alternate freshwater or marine aquatic
Solids	Ames mutagenicity Ram cytotoxicity Whole animal freshwater or marine aquatic Aquatic vertebrate Aquatic algal Aquatic invertebrate	Soil test	Additional cytotoxicity Alternate freshwater or marine aquatic
Solid leachates (aqueous extract)	Ames mutagenicity CHO cytotoxicity Whole animal (rodent acute) toxicity Freshwater or marine aquatic	--	WI 38 cytotoxicity Alternate freshwater or marine aquatic
SASS Train particulates	Ames mutagenicity CHO cytotoxicity	--	CHO cytotoxicity
SASS Train organics	Ames mutagenicity CHO cytotoxicity	--	WI 38 cytotoxicity
Gases	--	Plants stress ethylene test	--

*Based on Reference 102 and information supplied to TRW by Dr. R. Merril, EPA, Research Triangle Park, No. Carolina

†Dash indicates no test recommended at this time.

‡Includes aquatic vertebrate, algal and invertebrate tests

Despite the technical difficulties involved in estimating permissible concentrations of toxicants in emission streams, rational approaches are available for dealing with the problem. There are many potentially applicable formulae, some of them developed by or for the EPA and other governmental agencies. The formulae have two basic parts: a dose/response part and an adjustment part. The dose/response generally consists of one of the typical laboratory effects measurements: LD_{50}, LD_{LO}, and TL_m-96 hr.* Each effects measurement is adjusted by several factors, the argument being that the adjusted dose/response data better conform to the "real world" situation. Adjustments include the following: media conversion (e.g., air-borne to water-borne toxicants), safety factors (e.g., 0.01), various types of exposure (e.g., work day to full week), and elimination rate (e.g., biological half-life). In quantifying health effects on human populations, the notion of dose/response relationship takes on certain connotations. Dose characterization involves such items as numbers of people exposed, duration of exposure, and concentration of chemicals in the media. The effects are in terms of a change in the incidence or prevalence of certain diseases within the population. Thus, in its simplest form, a dose/response relationship might be characterized as "5 years of exposure to sulfur dioxide at 0.05 ppm causes an excess of 7 respiratory disease deaths per 100,000 population."

In the current early stages of the methodology development, some relatively broad classes of ratings are being used to indicate toxicity. These toxicity ratings are:

- No effect - no observed difference between test organisms and controls
- Low - a statistically significant difference can be observed

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*LD_{50}: Lethal dose 50, i.e., the dose which when administered to a group of animals is lethal to one-half of the population. The mode of administering the dose and the test animal must be specified.

LD_{LO}: Lethal dose low, i.e., the lowest dose of a substance introduced in one or more portions by any route other than inhalation over any period of time and reported to have caused death in a particular animal species.

TL_m: Median tolerance limit value, i.e., the concentration in water of a pollutant required to kill 50 percent of a particular aquatic species.

- Medium - an observable effect is produced by 10 to 99% of the maximum dose available in the system
- High - an effect is produced by only 10% or less of the maximum dose

It is anticipated that this methodology will change as a result of developmental work which will be continuing and because of feedback from the chemists and engineers who are expected to use the technique. However, it is expected to be useful in broadening the applicability of bioassay interpretation and in quantifying the effects in terms of significant difference between experimental organisms and human populations.

5.2 IMPACTS ON AIR

5.2.1 Summary of Air Standards and Guidelines

There are currently no Federal air emissions standards that apply specifically to gasification plants. EPA, however, has proposed standards and has recently published guidelines(22) for control of emissions from Lurgi coal gasification plants. New Mexico is presently the only state that has specific emissions regulations for gasification plants. Certain processes and operations within an integrated gasification plant (e.g., steam and power generation and coal preparation) would be covered by existing Federal and state regulations governing emissions from such sources.

EPA Guidelines for Control of Emissions from Lurgi Coal Gasification Plants(22). Currently, no commercial SNG coal gasification plants are either operating or under construction in the United States. Accordingly, much of the emission control technology that will be employed to reduce emissions has not been applied to coal gasification plants. A major area of uncertainty is how well these controls will work in this application. Because of this, it has been EPA's decision to temporarily delay the development and promulgation of standards for gasification plants. EPA, however, has carried out extensive background investigation and has developed a considerable data base for establishing such standards. The collected information, which has been subjected to public review and includes inputs from developers and industry groups, was recently published by EPA in summary form as a guideline document (EPA-450/2-78-012) entitled "Control of Emissions from Lurgi Coal Gasification Plants"(22).

The guideline document, which is subject to revision as new data become available, provides information on Lurgi coal gasification plants, their emissions, technologies which can be used to control emissions, and the environmental and economic impacts of applying these control technologies. Fuel conversion plants are included in the definition of major emitting sources under Section 169 of the Clean Air Act. This means that any coal gasification plant must obtain a permit before construction begins. The plant must apply best available control technoloty (BACT) before a permit is granted. Since EPA currently does not plan to develop a new source performance standard for Lurgi coal gasification plants, it has instead published the guideline document to enable state, local, and regional EPA enforcement personnel to determine BACT for Lurgi coal gasification plants on a case-by-case basis. The guideline document identifies the Rectisol process for acid gas removal as the major emission source within a Lurgi coal gasification plant. Gasifier lockhopper, sour water stripping, by-product recovery and catalyst regeneration and start-up gases are identified as secondary sources of emissions. Two alternative emission control systems (Systems I and II) are analyzed for the reduction of hydrocarbon and sulfur emissions contained in the gas streams discharged from the Rectisol process. System I consists of a Stretford sulfur recovery plant on the lean H_2S stream discharged from the Rectisol process and an ADIP H_2S concentration plant followed by a Claus sulfur recovery plant on the rich H_2S gas stream. This system reflects the minimal level of emission control being considered and thus represents the base case. Alternative emission control System II can consist of either (1) a Stretford sulfur recovery plant on the combined lean and rich H_2S gas streams discharged from the Rectisol process (Option II-1) or (2) a Stretford plant on the lean H_2S gas stream and an ADIP H_2S concentration plant followed by a Claus plant and Claus plant tail gas treatment on the rich H_2S gas stream (Option II-2) to reduce emissions to a level comparable to that obtained by the application of II-1.

Table 5-3 summarizes the emissions estimated from a 6.x x 10^{10} kcal/day (2.50 x 10^{11} Btu/day) Lurgi SNG coal gasification plant under alternative emission control Systems I and II and for the uncontrolled condition. The data in the table are for three types of coal which cover a rangeof candidate coals considered for first generation gasification plants. The coal types are (1) a western subbituminous coal of extremely low sulfur content, (2) a low sulfur

TABLE 5-3. EMISSIONS FROM A 63 TRILLION KCAL (250 BILLION BTU) PER DAY LURGI SNG COAL GASIFICATION PLANT WITH ALTERNATIVE EMISSION CONTROLS(22)

Pollutant	Uncontrolled			Alternative I			Alternative II (Options 1 and 2)					
	(a)†	(b)†	(c)†	(a)	(b)	(c)	1(a)	1(b)	1(c)	2(a)	2(b)	2(c)
SO_2	--	--	--	418 (922)	1,012 (2,234)	2,777 (6,131)	209 (461)	426 (941)	1,035 (2,285)	215 (474)	441 (973)	1,067 (2,355)
H_2S	2,563 (5,658)	8,847 (19,530)	26,541 (58,589)	--	--	--	--	--	--	--	--	--
HC‡	7,954 (17,559)	7,954 (17,559)	7,954 (17,559)	113 (250)	113 (250)	113 (250)	113 (250)	113 (250)	113 (250)	113 (250)	113 (250)	113 (250)
Total Sulfur, as S	2,424 (5,325)	8,327 (18,381)	24,980 (55,143)	209 (461)	506 (1,117)	1,389 (3,066)	104 (230)	213 (470)	517 (1,142)	107 (237)	220 (486)	534 (1,178)
Sulfur Recovery, %	0	0	0	91.3	93.9	94.5	95.7	97.4	97.9	95.6	97.4	97.9

*All numbers in kg/hr (lb/hr) except where noted

†Sulfur/heating value ratios of 0.72, 2.2 and 6.5 kg/sulfur/10^6 kcal (0.4, 1.2 and 3.6 lb sulfur/10^6 Btu), respectively

‡Non-methane hydrocarbons, average molecular weight = 29

western lignite, and (3) a high sulfur midwest bituminous coal. These coals have sulfur/heating value ratios of 0.72, 2.2 and 6.5 kg sulfur/10^6 kcal (0.4, 1.2 and 3.6 lb sulfur/10^6 Btu), respectively. As noted in the table, alternative emission control System I achieves 91 to 95 percent control of sulfur compound emissions while alternative emission control System II achieves 96 to 98 percent control of sulfur compound emissions.

The two alternative control systems should achieve nearly the same level of hydrocarbon emission control. Since sulfur emissions must be controlled, coal gasification plants will select either the Stretford-Claus or the Stretford-only emission control system. Where the Stretford-Claus approach is selected, the Claus plant will not be an emission source of non-methane hydrocarbons, since the hydrocarbons present in the rich waste gas stream will be removed prior to the Claus plant in an H_2S concentration unit such as the ADIP process. Where the Stretford-only approach is selected, incineration of the tail gas would be required.

The EPA guidelines document reviews the advantages and disadvantages of establishing emission standards for gasification plants based on "mass" emission limits and "concentration" emission limits. In general, mass limits are more meaningful than concentration limits because mass limits relate directly to the quantity of emissions discharged into the atmosphere. Enforcement of mass limits is usually more complex and costly due to the need for a material balance of some sort requiring process data concerning the operation of the plant. A major disadvantage of the concentration limits is that of possible circumvention by dilution of the pollutants being discharged to the atmosphere, thus lowering the concentration of the pollutant but not the total mass emitted. A review of the process flow sheets for the proposed commercial Lurgi SNG plants indicates that there are any number of possibilities for mixing various gas streams, many of which would substantially alter the volume and hence the concentration of emissions, but not the mass of emissions released to the atmosphere Accordingly, standards predicated on mass of pollutants emitted are considered preferable over concentration limits for the Lurgi SNG plants.

Whether a mass or a concentration format is selected, the numerical emission limit must vary depending on the properties of coal processed. For Lurgi SNG plants the sulfur emissions would most closely correlate with the coal sulfur content and the coal heating value* and the hydrocarbon emissions correlate most closely with the coal heating value. Based on the data in Table 5-3, the following general formulas have been suggested for estimating sulfur and hydrocarbon emissions:

$$ES = 0.07\ (S_c)^{0.85}\ (HHV_c)^{0.15} \text{ for Control System I}$$

$$ES = 0.032\ (S_c)^{0.75}\ (HHV_c)^{0.25} \text{ for Control System II}$$

$$EHC = 0.07\ HHV_c \text{ for Control Systems I and II}$$

where

ES = total sulfur emissions (kg/hr)
S_c = coal sulfur input (kg/hr)
HHV_c = coal heat input (MW)
EHC = emissions of non-methane hydrocarbons (kg/hr)

Selection of the alternative emission control systems has focused only on the waste gas streams discharged from the Rectisol process. As noted earlier, other emission sources exist within coal gasification plants. The Rectisol process, however, is by far the major and most significant emission source accounting for about 95 percent of the potential sulfur emissions and about 85 percent of the potential hydrocarbon emissions. Furthermore, for a number of these other emission sources, the obvious emission control technique is to combine the waste gas streams discharged with those discharged from the Rectisol process and control the combined gas streams. The emissions estimates shown in Table 5-3 for alternative emission control Systems I and II assume control of the waste gas streams discharged from other emission sources as follows:

Coal gasifier coal lock:

(a) Pressurization of the coal lock with an inert gas such as N_2 or CO_2 with release of these gases, as the lock is depressurized to about 1.8 MPa (250 psig), to a gas collection and storage system for recycle to the coal lock when it is repressurized. Residual gases released as the lock is depressurized below 1.8 MPa (250 psig) are released directly to the atmosphere.

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*The waste gas streams discharged by a Lurgi SNG plant are predominantly carbon dioxide (i.e., 50-95 percent CO_2). The coal heating value, or the higher heating value (HHV), is a function of the coal carbon content, and the carbon content determines the volume of the CO_2 gas produced.

(b) Or alternatively, pressurization of the coal lock with raw coal gas with release of these gases to the Rectisol emission control system as the lock is depressurized to about 0.1 MPa (0.5 psig). Residual gases released as the lock is depressurized completely are released directly to the atmosphere.

Sour water stripping:

Control of these gases in the Rectisol emission control system.

By-product recovery, catalyst regeneration and startup:

Control of these gases by incineration or flares.

The above equations are based on a number of assumptions including some relating to gas compositions and anticipated performance of the alternative emission control systems. Some revisions to the above equations or adjustments to the calculated emission limit may become necessary as data become available from actual operations.

Miscellaneous Federal and State Standards Affecting Air Emissions from Lurgi SNG Plants. Even though there are currently no federal or state (except for New Mexico) standards that apply specifically to coal gasification plants, a number of federal and state air emissions and ambient air quality standards are currently in effect or are being developed which would impact the operation of coal gasification plants or specific process/units within an integrated SNG facility. These standards include:

National and State Ambient Air Quality Standards
Prevention of Significant Deterioration (PSD) Regulations
New Source Performance Standards for:
    fossil fuel steam generation
    coal preparation
    incineration
    hydrocarbon storage vessels
    sulfur recovery plants
New Mexico Emission Standards for Coal Gasification Plants

The 1970 Federal Clean Air Act Amendments established a common framework for federal, state and local governments to work together for the control of air pollutants and achievement of a cleaner air. The provisions of this act were expanded and made more specific by the recent enactment of the Clean Air Act Amendments of 1977. Key elements of these legislations include:

- Promulgation by EPA of national ambient air quality standards (NAAQS) for major pollutants, including NO_x, SO_x and total suspended particulates (TSP), with states having the option to establish more stringent standards if they so desire.

- Development and submission for EPA approval by states of state implementation plans (SIPs) which specify how the NAAQS (or their own state standards, if more stringent) will be achieved (including emission limitations, compliance schedules and enforcement provisions) within three years of promulgation of the SIPs.

- Establishment by EPA of national emission standards for certain source categories; Sections 111 and 112 of the Act directs EPA to establish standards of performance for new sources and national emission standards for hazardous air pollutants.

- Prevention of significant air quality deterioration by states in those cases where the air quality is already better than NAAQS.

National Ambient Air Quality Standards. Under Section 109 of the Act, EPA is required to set two basic types of ambient air quality standards: primary standards (for the protection of human health) and secondary standards (for the protection of public welfare). The two sets of standards, promulgated in 1971, are presented in Table 5-4. Thirty-five states have promulgated state ambient SO_2 standards more stringent than NAAQS. The ambient TSP standards for fifteen states are more stringent than NAAQS. None of the states have more stringent NO_x standards. Table 5-5 lists standards for selected states which are sites for proposed commercial gasification plants or are candidates for siting such facilities (see Sections 2.1.6 and 4.8 for siting considerations for Lurgi coal gasification facilities).

Prevention of Significant Deterioration of Air Quality(104). The Clean Air Act (Part C) authorizes a preconstruction review and permitting authority for major facilities in areas that are cleaner than the NAAQS. Table 5-6 shows the maximum permissible increase in concentration above baseline values under various averageable conditions for "Class I," "Class II," and "Class III" areas. The 1977 Amendments designate the following mandatory Class I Federal areas: international parks, wilderness areas in excess of 2080 hectares (5000 acres), national memorial parks in excess of 2080 hectares (5000 acres), and national parks in excess of 2500 hectares (6000 acres). Initially, all other areas are designated as Class II, but the states may, under certain conditions, re-designate certain areas toward either the more pristine Class I or the "dirtier"

TABLE 5-4. NATIONAL AMBIENT AIR QUALITY STANDARDS FOR CRITERIA POLLUTANTS(104)

Pollutant	Pollutant Standard	
	Primary*	Secondary†
Nitrogen dioxide	100 μg/m^3 (0.05 ppm) annual arithmetic mean	Same as primary
Carbon monoxide	10 mg/m^3 (9 ppm) maximum 8-hour average 40 mg/m^3 (35 ppm) maximum 1-hour average	Same as primary
Sulfur dioxide	80 μg/m^3 (0.03 ppm) annual arithmetic mean 365 μg/m^3 (0.14 ppm) maximum 24-hr. average	1300 μg/m^3 (0.05 ppm) maximum 3-hour average
Organics	160 μg/m^3 (0.24 ppm) maximum 3-hour average 6 to 9 A.M.	Same as primary
Total suspended particulate	75 μg/m^3 annual geometric mean 260 μg/m^3 maximum 24-hour average	60 μg/m^3 annual geometric mean 150 μg/m^3 maximum 24-hour average
Photochemical oxidant	160 μg/m^3 (0.08 ppm) maximum 1-hour average	Same as primary

*Primary, necessary to protect the public health

†Secondary, necessary to protect the public welfare

TABLE 5-5. SUMMARY OF STATE AMBIENT AIR QUALITY REGULATIONS(102)

Region: State	NO_2	SO_2	Hydrocarbons	Suspended Particulate
Eastern Interior:				
Illinois	100 μg/m³ Annual arithmetic mean	Primary: (1) 80 μg/m³ (0.03 ppm) Annual arithmetic mean (2) 365 μg/m³ (0.14)⁺ Maximum 24-hr average Secondary: (1) 1,300 μg/m³ (0.5 ppm) Maximum 3-hr average	Non-methane hydrocarbons measured as methane: 160 μg/m³ (0.24 ppm)⁺ Maximum 3-hr average 6-9 a.m.	Primary: (1) 75 μg/m³ Annual geometric mean (2) 260 μg/m³⁺ Maximum 24-hr average Secondary: (1) 60 μg/m³ Annual geometric mean (2) 150 μg/m³⁺ Maximum 24-hr average
Indiana	Same as above	Same as above	Same as above	Primary: Same as above Secondary: 150 μg/m³⁺ Maximum 24-hr average
Kentucky	Same as above	Same as above	Same as above	Primary: (1) 75 μg/m³ Annual geometric mean (2) 260 μg/m³⁺ Maximum 24-hr average (3) Soiling index:⁺⁺ 6.0 COH/1000 LF Maximum 24-hr average Secondary: (1) 60 μg/m³ Annual geometric mean (2) 150 μg/m³⁺ Maximum 24-hr average (3) 0.4 COH/1000 LF Annual arithmetic mean (4) 0.5 COH/1000 LF Maximum 3-mo average (5) 0.3 COH/1000 LF⁺ Maximum 24-hr average (6) Settleable particulates: 5.25g/m²/mo Maximum 3-mo average

(continued)

TABLE 5-5. CONTINUED

Region: State	NO$_2$	SO$_2$	Hydrocarbons	Suspended Particulate
Pennsylvania	Same as Federal standards	Same as Federal standards	Same as Federal standards	Settled Particulate: (1) 0.8 μg/cm^2/mo Annual average (2) 1.5 μg/cm^2/mo 30-day average
West Virginia	None	Primary: (1) 80 μg/m^3 (0.03 ppm) Annual arithmetic mean (2) 365 μg/m^3 (0.14 ppm)$^+$ Maximum 24-hr average Secondary: (1) 1,300 μg/m^3 (0.50 ppm)$^+$ Maximum 3-hr average (2) 260	None	Primary: (1) 75 μg/m^3 Annual geometric mean (2) 260 μg/m^3$^+$ Maximum 24-hr average Secondary: (1) 60 μg/m^3 Annual geometric mean (2) 150 μg/m^3$^+$ Maximum 24-hr average
Ohio	100 g/m^3 Annual arithmetic mean	(1) 60 μg/m^3 (0.02 ppm) Annual arithmetic mean (2) 260 μg/m^3 (0.10 ppm)$^+$ Maximum 24-hr average	Non-methane hydrocarbons measured as carbon (1) 126 μg/m^3 (0.19 ppm) Maximum 3-hr average between 6 and 9 a.m. (2) 331 μg/m^3 (0.50 ppm)$^+$ Maximum 24-hr average	(1) 60 μg/m^3 Annual geometric mean (2) 150 μg/m^3$^+$ Maximum 24-hr average
Northeastern Great Plains:				
North Dakota	(1) 100 g/m^3 (0.05 ppm) Annual arithmetic mean (2) 200 g/m^3 (0.10 ppm) Maximum 1-hr average not to be exceeded more than 1% of the time	(1) 60 μg/m^3 (0.02 ppm) Annual arithmetic mean (2) 260 μg/m^3 (0.10 ppm) Maximum 24-hr average (3) 715 μg/m^3 (0.28 ppm) Maximum 1-hr average	Non-methane as methane: 160 μg/m^3 (0.24 ppm)$^+$ Maximum 3-hr average between 6 and 9 a.m.	Suspended: (1) 60 μg/m^3 Annual geometric mean (2) 150 μg/m^3$^+$ Maximum 24-hr average Settled: (1) 5.25 g/m^2/mo (15 tons/mi^2/mo) Maximum 3-mo average om residential areas (2) 10.50 g/m^2/mo (30 tons/mi^2/mo Maximum 3-mo average in industrial areas

(continued)

TABLE 5-5. CONTINUED

Region: State	NO_2	SO_2	Hydrocarbons	Suspended Particulate
Northwestern Great Plains:				Coefficient of haze:++ 0.4 COH/1000 LF Annual geometric mean
Montana	None	(1) 0.02 ppm Annual average (2) 0.10 ppm 24-hr average not to be exceeded more than 1% of the days in any 3-month period (3) 0.25 ppm not to be exceeded for more than 1-hr in any 4 consecutive days	None	Suspended: (1) 75 µg/m^3 Annual geometric mean (2) 200 µg/m^3 Not to exceed more than 1% of the days a year Settled: (1) 5.25 g/m^2/mo (15 tons/mi^2/mo) in residential areas (2) 10.50 g/m^2/mo (30 tons/mi^2/mo) in industrial areas
Wyoming	100 µg/m^3 (0.05 ppm) Annual arithmetic mean	(1) 60 µg/m^3 (0.2 ppm) Annual arithmetic mean (2) 260 µg/m^3 (0.10 ppm) Maximum 24-hr average not to be exceeded more than once per year (3) 1,300 µg/m^3 (0.50 ppm) Maximum 3-hr average not to be exceeded more than once per year	Non-methane measured as methane: 160 g/m^3 (0.24 ppm) Maximum 3-hr average between 6 and 9 a.m.	Suspended: (1) 60 µg/m^3 Annual geometric mean (2) 150 µg/m^3 Maximum 24-hr average Soiling index:++ (1) 0.4 COH/1000 LF Annual geometric mean Settleable: (1) 5 g/m^2/mo for any 30-day period in residential areas (2) 10 g/m^2/mo for any 30-day period in industrial areas
Rocky Mountain:				
Colorado	None	Outside of Air Quality Control Areas: 15 µg/m^3 Maximum 24-hr average not to be exceeded more than once in any 12-mo period Within Air Quality Control Areas: (1) 10 µg/m^2 Annual arithmetic mean (2) 55 µg/m^3 Maximum 24-hr Average not to be exceeded more than once in any 12-month period	None	(1) 45 µg/m^3 Annual*** arithmetic mean (2) 150 µg/m^3 Maximum 24-hr average not to be exceeded more than once in any 12-mo period

(continued)

TABLE 5-5. CONTINUED

Region: State	NO_2	SO_2	Hydrocarbons	Suspended Particulate
New Mexico	(1) 0.05 ppm Annual arithmetic average (2) 0.10 ppm 24-hr average	(1) 0.02 ppm Annual arithmetic average (2) 0.10 ppm 24-hr average	Non-methan hydrocarbons: 0.19 ppm 3-hr average	Suspended: (1) 60 $\mu g/m^3$ Annual geometric mean (2) 90 $\mu g/m^3$ 30-day average (3) 110 $\mu g/m^3$ 7-day average (4) 150 $\mu g/m^3$ 24-hr average Soiling index:[++] 0.4 COH/1000 LF Annual average

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[+] Not to be exceeded more than once per year.

[++] "Soiling Index" means a measure of the soiling property or suspended particles in air determined by drawing a measured volume of air thorough a known area of Whatman No. 4 filter for a measured period of time, expressed as COH (Coefficient of Haze)/1000 LF (Linear feet).

[*] Dilutions with odorless air to reduce odor to below odor threshold level.

[**] Note the terms suspended sulfate, sulfation and SO_3 are not used in a consistent manner by the states.

[***] In all areas on or before 1 January 1980.

Class III. However, the reclassification as Class III requires an extensive public hearing procedure.

TABLE 5-6. MAXIMUM PERMISSIBLE INCREMENTS FOR SULFUR DIOXIDE AND PARTICULATE MATTER CONCENTRATIONS IN AMBIENT AIR FOR EACH PSD CLASS COMPARED TO NAAQS VALUES (QUANTITIES IN MG/M^3)

Pollutant	Period for Averaging	Maximum Concentration Increments Class I	Class II	Class III	NAAQS
SO_2	Annual	2	20	40	80
	24-hour	8	91	182	365
	3-hour	25	512	700	1300*
TSP	Annual	5	19	37	7560*
	24-hour	10	37	75	260,150*

*Secondary standards

By August 1979 the EPA must also promulgate classification incremental values for hydrocarbons, carbon monoxide, photochemical oxidants and nitrogen oxides. For any other pollutant for which NAAQS are established, EPA must promulgate classification incremental values within two years of promulgation of the standard.

In order to protect Class I areas, no major emitting facility can be constructed without a permit establishing emission limitations. Prior to the issuance of such a permit, EPA must require an analysis of the ambient air quality and visibility, climate and meteorology, terrain, soils, and vegetation, both at the site of the proposed facility and in the area potentially affected by emissions from the facility, for each pollutant regulated under the Clean Air Act. Furthermore, EPA must determine the degree of continuous emission reduction which could be achieved by the facility.

Another regulatory approach has been made possible under Part D of the Clean Air Act. This deals with "non-attainment areas," i.e., those which are polluted above the levels necessary to protect health and welfare. It puts into effect an off-set policy which, in effect, can regulate industrial growth in such areas. In order to issue a permit to a major new source which seeks to locate in the non-attainment area, the state must show that the total emissions from all sources in the area will be sufficiently less than the total emissions allowed for existing sources prior to construction of the major new source. In other words, the baseline for calculating offset is the total emissions allowed in the SIP without taking the new source into consideration. As a condition for permitting major new stationary sources to locate in non-attainment areas, the states are required to obtain EPA approval for revised SIPs which include provision for attainment of the primary NAAQS values (health realted standards) no later than December 31, 1982, except for photochemical oxidant and carbon monoxide, for which attainment is delayed until December 31, 1987. Among other things the new SIP must include a permit program for new stationary sources in which they must operate at the "lowest achievable emission rate" reflecting the most stringent emission limitation contained in any SIP for any such class or category of source, or the most stringent emission limitation which has been achieved in practice whichever is most restrictive.

New Source Performance Standards (NSPS). Section III of the Clean Air Act requires EPA to set standards of performance for new or modified stationary (point) sources. These are nationally applicable direct emission limitations for specific source types (e.g., fossil fuel-fired steam generators). This limitation reflects the pollutant reduction achievable through use of the best technological system of continuous emission control (taking into account cost, non-air quality health and environmental impact and energy requirements) which the EPA determines has been adequately demonstrated. In those cases where it is not feasible to prescribe or enforce a standard of performance, the Administrator may, instead, promulgate a design, equipment, work practice or operational standard - or a combination of these - which has been determined to adequately demonstrate the best technological system of continuous emission reduction (taking into account cost, non-air quality health and environmental impact and energy requirements). These NSPS regulations must be reviewed and revised, if appropriate, every four years.

Several emissions sources in a Lurgi SNG facility would be subject to Federal NSPS. Table 5-7 summarizes these standards for fossil fuel- and lignite-fired steam generators, coal preparation plants, solid waste incinerators and hydrocarbon storage vessels.

National Emission Standards for Hazardous Air Pollutants (NESHAP). Section 112 of the Clean Air Act defines a hazardous air pollutant as one for which no NAAQS is applicable and which, in the judgment of the EPA, causes or contributes to air pollution in a manner that may result in an increase of mortality or irreversible or incapacitating reversible illness. Section 112 authorizes the

TABLE 5-7. SUMMARY OF FEDERAL EMISSION STANDARDS APPLICABLE TO INTEGRATED LURGI SNG FACILITIES

Air Standard or Guideline	Applicable Source	NO_x (as NO_2)	SO_2 (Sulfur)	Non-methane Hydrocarbons	Particulates
1. Fossil Fuel Steam Generators (except lignite) NSPS	Power plant (steam and electric generation) and steam superheater			None	
- Coal and coal derived fuels					
• Subbituminous coal and liquid and gaseous fuels derived from coal		0.88 g/MM cal,(106) (0.210 ng/J) (0.50 lb/MM Btu)	2.2 g/MM cal(106) (520 ng/J) (1.2 lb/MM Btu) AND 85% control unless 0.36 g/MM cal (86 ng/J) (0.20 lb/MM Btu)		
• Bituminous coal		1.1 g/MM cal,(106) (260 ng/J) (0.60 lb/MM Btu)			
- Gaseous and liquid fuels not derived from coal					0.054 g/MM Btu,(106) (13 ng/J) (0.030 lb/MM Btu) AND 20% opacity
• Gaseous fuels		0.36 g/MM cal,(107) (86 ng/J) (0.20 lb/MM Btu)	1.4 g/MM cal,(106) (340 ng/J) (0.80 g/MM Btu) AND 85% control unless 0.36 g/MM cal (86 ng/J) (0.20 g/MM Btu)		
• Liquid fuels		0.54 g/MM cal,(107) (130 ng/J) (0.30 lb/MM Btu)			
2. Lignite Fuel Steam Generators NSPS	Power plant (steam and electric generation) and steam superheater	1.1 gm/MM cal,(103) (260 ng/J) (0.6 lb/MM Btu)	2.2 g/MM cal,(106) (520 ng/J) (1.2 lb/MM Btu) AND 85% control unless 0.36 g/MM cal (86 ng/J) (0.20 g/MM Btu)	None	
3. Coal Preparation, NSPS	Coal preparation operations for gasifier and power plant	None	None	None	i Pneumatic cleaning(130) equipment: 0.040 g/dscm (0.018 g/dscf) AND 20% opacity ii Processing and conveying equipment: 20 opacity
4. Incineration NSPS	Solid waste incineration	None	None	None	0.18 g/Nm^3 (0.08 grains/scf corrected to 12% O_2(132)
5. Hydrocarbon Storage Vessels NSPS	By-product storage	None	None	Equipment specifications based on vapor pressure	None

EPA to set emission standards for these hazardous substances which are applicable to any new source or modified existing sources. To date NESHAP's have been promulgated for asbestos, beryllium, mercury, and vinyl chloride. None of these substances is expected to be a major emission problem for Lurgi SNG facilities.

New Mexico State Emission Standards for Gasification Plants. New Mexico is the only state at present which has developed regulations for gasification plants. As indicated in Table 5-8, the state has chosen a combination of mass and concentration limits for various gaseous pollutants associated with the gasification plant. Mass limits have been established for gas-fired power plants associated with SNG facilities.

5.2.2 Comparison of Waste Streams with Emissions Standards

In this section emissions estimates for Lurgi SNG plants are compared with the Federal guidelines and the New Mexico state standards for such plants. Also, the emissions from on-site steam and power generation at Lurgi plants are compared with the corresponding Federal standards. Emission estimates considered are: (a) those reported for five proposed commercial projects and (b) those prepared in this study for the five control options analyzed (see Section 4.2.5).

Table 5-9 compares the estimated total sulfur emissions from gasification with the appropriate Federal guidelines and New Mexico standards. The data in this table indicate that the two plants to be located in New Mexico (WESCO and El Paso) would meet both the Federal guidelines and the New Mexico state standards, whereas the two plants proposed for North Dakota (ANG and Dunn Co.) would exceed both the Federal guidelines and New Mexico standards. The proposed Wyoming plant would meet the Federal guidelines only. It should be noted that the designs for all the proposed commercial plants were prepared before the publication of the Federal guidelines and that the New Mexico standards would only apply to plants located in New Mexico. Except for Option 4, the control options examined meet the Federal guidelines. Option 4 employs FGD systems for combined treatment of the incinerated Rectisol acid gases and boiler flue gases; FGD systems are generally not as effective as acid gas treatment via sulfur recovery used in other options. Only Option 3, which features sulfur recovery/ tail gas treatment, meets the more stringent New Mexico standards.

TABLE 5-8. NEW MEXICO EMISSION REGULATIONS APPLICABLE TO LURGI SNG PLANTS(105)

Pollutant	Emission Limits for Gas-Fired Power Plant Associated with Gasification Plant	Emission Limits for Direct Emissions from Gasification Plant
Sulfur compounds	0.28 grams/10^6 cal* (0.16 lbs $SO_2/10^6$ Btu)	1) 0.015 grams total sulfur per 10^6 cal of coal feed* (0.008 lbs/10^6 Btu) 2) 100 ppm sum of H_2S, COS, and CS_2 3) 10 ppm H_2S
Particulate matter	0.053 grams/10^6 cal (0.03 lbs/10^6 Btu)	.065 grams/Nm^3 (.03 grains/scf)
Oxides of nitrogen	3.5 grams/10^6 cal (0.02 lbs/10^6 Btu) (as NO_2)	--
Hydrogen cyanide (HCN)	--	10 ppm
Hydrochloric acid (HCl)	--	5 ppm
Ammonia (NH_3)	--	25 ppm

*Based on HHV of fuel

TABLE 5-9. COMPARISON OF ESTIMATED SULFUR EMISSIONS FROM LURGI GASIFICATION PLANTS WITH APPROPRIATE EMISSION GUIDELINES/STANDARDS*

Pollutant Source	Project/ Control Options	Estimated Emissions		Applicable Federal Standard	Applicable New Mexico Standard	Meets/Exceeds Federal Guideline	Meets/Exceeds New Mexico Standard
		kg/hr (lb/hr)	g/MM cal (lb/MM Btu)	kg/hr (lb/hr)	kg/MM cal (lb/MM Btu)		
	Projects						
Gasification plant	WESCO	77 (170)	0.019 (0.011)	1016 (2240)	0.029 (0.016)	Meets	Meets
	El Paso	116 (256)	0.029 (0.016)	354 (780)	0.029 (0.016)	Meets	Meets
	ANG	545 (1202)	0.14 (0.075)	444 (979)	0.029 (0.016)	Exceeds	Exceeds
	Wyoming	164 (362)	0.041 (0.023)	1118 (2465)	0.029 (0.016)	Meets	Exceeds
	Dunn Co.	460 (1014)	0.11 (0.063)	192 (423)	0.029 (0.016)	Exceeds	Exceeds
	Control Options[†]						
	Option 1	250 (551)	0.061 (0.034)	354 (780)	0.029 (0.016)	Meets	Exceeds
	Option 2	250 (551)	0.061 (0.034)	354 (780)	0.029 (0.016)	Meets	Exceeds
	Option 3	20 (44)	0.005 (0.003)	354 (780)	0.029 (0.016)	Meets	Meets
	Option 4	1200 (2650)	0.31 (0.17)	354 (780)	0.029 (0.016)	Exceeds	Exceeds
	Option 5	240 (529)	0.060 (0.033)	354 (780)	0.029 (0.016)	Meets	Exceeds

*All values are expressed as SO_2

[†] See Section 4.2.5 for description of options which are applied to emission streams considered in this study.

The Federal guidelines would allow approximately 300 kg/hr of non-methane hydrocarbons to be emitted from a 7 x 10^6 Nm^3/d (250 MMscf/d) plant. This is based on the use of incineration for the control of sulfur recovery tail gases. Accordingly, when off-gases are incinerated in a Lurgi plant (alone or in conjunction with steam and power generation) the Federal standards should be met. Actual operating data are not available on the efficiency of off-gas incineration systems for distribution of HC in off-gases. Since it is generally assumed that the incineration of off-gases for the control of HC emissions also results in the destruction of CO, no guidelines have been developed for CO emissions.

Tables 5-10, 5-11 and 5-12 compare the estimated emissions of SO_2, particulates and NO_x from onsite power and steam generation with the Federal standards. As with the gasification emissions, the New Mexico projects, which were designed to meet the more stringent state standards (for fossil fuel-fired boilers), meet the Federal standards for all three pollutants. The designs for the proposed plants in North Dakota and Wyoming were prepared before the promulgation of the Federal standards; additional pollution control would be required for these plants in order to meet the Federal standards. All five control options examined would meet the SO_2 emissions standards. The emissions factors used to estimate particulate and NO_x emissions are those reported in AP-42(109) and are generally for controls which are less stringent than those required to meet the new Federal standards. Accordingly, the estimated particulate and NO_x emissions for the five options somewhat exceed the new Federal standards.

5.2.3 Impacts on Ambient Air Quality

Ambient air quality modelling has been conducted for four of the five proposed commercial Lurgi SNG plants and in conjunction with the development of Federal guidelines for Lurgi SNG plants. The predicted maximum ground level concentrations for various averaging times are presented in Table 5-13 for the four plants and for the two control options considered by EPA in developing Federal guidelines. While there are some differences between the predicted concentrations for the cases considered, in all cases the predicted levels are well below the Federal and state ambient standards for SO_2, NO_x, non-methane hydrocarbons and particulates, and carbon monoxide (see Tables 5-4 and 5-5 for ambient air quality standards). The observed differences reflect differences in emission levels, assumed stack heights and locations, meteorological conditions and the particular diffusion model used.

TABLE 5-10. COMPARISON OF SO_2 EMISSIONS FROM ONSITE STEAM AND POWER GENERATION WITH APPROPRIATE FEDERAL STANDARDS

Project/ Control Options	Estimated Emissions		Federal Standard	Meets/Exceeds Federal Standard
	kg/hr (lb/hr)	$g/10^6$ cal ($lb/10^6$ Btu)	$g/10^6$ cal ($lb/10^6$ Btu)	
Project				
WESCO	265 (584)	0.29 (0.16)	0.56 (0.32)	Meets
El Paso	41 (90)	0.058 (0.032)	0.45 (0.25)	Meets
ANG	640 (1410)	1.3 (0.72)	0.94 (0.52)	Exceeds
Wyoming	1035 (2282)	1.3 (0.73)	0.36 (0.2)	Exceeds
Dunn Co.	860 (1900)	0.90 (0.50)	0.67 (0.37)	Exceeds
Control Options*				
Option 1	150 (330)	0.21 (0.12)	0.45 (0.25)	Meets
Option 2	20 (44)	0.03 (0.02)	0.36 (0.2)	Meets
Option 3	280 (620)	0.40 (0.22)	0.45 (0.25)	Meets
Option 4	300 (660)	0.43 (0.24)	0.45 (0.25)	Meets
Option 5	280 (620)	0.40 (0.22)	0.45 (0.25)	Meets

*See Section 4.2.5 for description of options

TABLE 5-11. COMPARISON OF ESTIMATED PARTICULATE EMISSIONS FROM ONSITE STEAM AND POWER GENERATION WITH FEDERAL EMISSION STANDARDS

Project/ Control Option	g/MM cal (lb/MM Btu)		Meets/Exceeds Federal Standards
	Estimated Emissions	Federal Standards	
Proposed Projects			
El Paso	<.05 (0.03)	--	Meets
WESCO	0.020 (0.011)	0.054 (0.030)	Exceeds
ANG	0.13 (0.072)	0.054 (0.030)	Meets
Wyoming	0.034 (0.018)	0.054 (0.030)	Exceeds
Dunn Co.	0.175 (0.097)	0.054 (0.030)	--
Control Options*			
Option 1	0.09 (0.05)	0.054 (0.030)	Exceeds
Option 2	--	None	--
Option 3	0.07 (0.04)	0.054 (0.030)	Exceeds
Option 4	0.07 (0.04)	0.054 (0.030)	Exceeds
Option 5	0.07 (0.03)	0.054 (0.030)	Exceeds

*See Section 4.2.5 for description of options

TABLE 5-12. COMPARISON OF ESTIMATED NO_X EMISSIONS FROM ONSITE STEAM AND POWER GENERATION WITH FEDERAL STANDARDS

Project/ Control Option	g/MM cal (lb/MM Btu)		Meets/Exceeds Federal Standards
	Estimated Emissions	Federal Standards	
Proposed Projects			
El Paso	0.36 (0.2)	0.88 (0.50)	Meets
WESCO	0.45 (0.25)	0.88 (0.50)	Meets
ANG	1.0 (0.55)	1.1 (0.6)	Meets
Wyoming	1.3 (0.70)	0.88 (0.50)	Exceeds
Dunn Co.	1.3 (0.72)	1.1 (0.6)	Exceeds
Control Options*			
Option 1	1.3 (0.7)	0.88 (0.50)	Exceeds
Option 2	2.0 (1.11)	0.88 (0.50)	Exceeds
Option 3	1.6 (0.89)	0.88 (0.50)	Exceeds
Option 4	1.4 (0.78)	0.88 (0.50)	Exceeds
Option 5	1.6 (0.89)	0.88 (0.50)	Exceeds

*See Section 4.2.5 for description of options

TABEL 5-13. MAXIMUM PREDICTED GROUND-LEVEL CONCENTRATIONS ASSOCIATED WITH LURGI SNG FACILITIES[*]

Plant/Option	Averaging Time	μg/m³				
		NO_x	SO_2	NMHC[†]	Particulates	CO
WESCO	Annual	2.3	1.3	--	1	--
	24-hour	4.6	2.4	--	1	--
	3-hour	98	51	0.16 ppm[‡]	3	--
ANG[§]	Annual	0.5	2.4	--	0.1	--
	24-hour	--	24.3	--	0.8	--
	3-hour	--	61.8	--	--	--
	1-hour	32.5	152.8	--	--	--
El Paso	Annual	3.5	3.2	--	--	--
	24-hour	23	21	--	--	--
	3-hour	--	123	--	--	--
Wyoming	Annual	17	13	--	1	--
	24-hour	--	44	--	3	--
	3-hour	--	218	--	--	--
EPA Control Option I	Annual	--	1-5	<1	--	--
	24-hour	--	15-100	--	--	--
	8-hour	--	--	--	--	1-3
	3-hour	--	100-700	3-5	--	--
EPA Control Option II	Annual	--	1-5	<1	--	--
	24-hour	--	10-70	--	--	--
	8-hour	--	--	3-5	--	1-3
	3-hour	--	100-450	--	--	--

[*] See Tables 5-4 and 5-5 for Federal and state ambient air quality standards.

[†] Non-methane hydrocarbons

[‡] ppm as CH_4

[§] Attributable to gasification facility only; a large power plant is also to be located nearby.

For the two EPA control options, the PSD increment for a Class II Region would be met by plants gasifying low to medium sulfur coals. However, when high sulfur coals are to be handled, the PSD increment for a Class II Region may be exceeded (at least for control Option 1). Comparison of the data in Table 5-13 for Options 1 and 2 indicate very little improvement in ambient air quality as a result of the more stringent SO_2 control in Option 2. This is primarily due to the overriding effects of the emissions from onsite power and steam generation.

Except for the SO_2 emissions for Option 4, the estimated emissions associated with the control options examined in this study are lower than those used in calculating concentration levels shown in Table 5-13. Accordingly, the ground level concentrations resulting from the application of these control options should be lower than those shown in Table 5-13 (assuming similar stack heights, locations, etc.). Although a somewhat higher SO_2 emission is associated with Option 4, the increase in ambient level concentration would be small and not likely to result in the violation of the ambient SO_2 standard.

Although neither the predicted ambient NO_x nor non-methane hydrocarbon levels shown in Table 5-13 exceed the air quality standards, a recent study(110) has suggested that the oxidants resulting from the photochemical reactions of these pollutants may exceed the NAAQS for oxidants. This study, however, assumes HC and NO_x emissions of about 1000 kg/hr and 2100 kg/hr, respectively. These emission levels are about three times as much as those which would be allowed in order to meet the Federal standards/guidelines for Lurgi SNG plants. Ambient oxidant levels which would be expected from lower NO_x and non-methane HC emission levels have not been estimated.

5.2.4 Evaluation of Unregulated Pollutants and Bioassay Results

Unregulated (non-criteria) pollutants present in emissions from Lurgi SNG facilities may include reduced sulfur and nitrogen compounds (H_2S, COS, CS_2, mercaptans, HCN and NH_3), HCl, aromatic hydrocarbons, heterocyclic organics, metal carbonyls, organometallic compounds, and trace elements. Although limited data are available on the concentration of some of these substances in certain untreated gaseous waste streams in a Lurgi plant, no data are available on the concentration of residuals (if any) in the final emissions to allow estimation of the ambient impact. Incineration, which is the proposed control for all gases before atmospheric discharge, is expected to convert most of the above types of substances to harmless compounds (e.g., CO_2), or to criteria pollutants (e.g., SO_2, NO_x and particulates).*

Incineration of waste gases would convert most trace elements to oxides which become components of the particulate matter. Some trace elements (e.g., mercury, arsenic, selenium, fluorine and chlorine) would appear in the final emissions as gaseous compounds. Based on mass balance calculations (see data in Chapter 3), in the gasification of coals essentially 100 percent of most trace elements can be found in the ash, tar, oil and gas liquor. Accordingly, negligible quantities of trace elements are expected to be found in gaseous emissions associated with the gasification, gas purification and gas upgrading operations. Onsite steam and power generation using coal or gasification by-products as fuels may result in emissions of the more volatile trace elements (e.g., Hg, F, Cl) to the atmosphere. The amount of trace element emissions from fuel combustion is determined largely by the feed coal composition and by the pollution control equipment used.

Although no bioassay data are currently available for gaseous emissions from Lurgi gasification plants, such data are currently being collected in connection with the EPA (IERL/RTP) sampling and analysis program at the Kosovo plant. Bioassay data have also been collected by EPA for other gasification processes.

5.3 IMPACT ON WATER

5.3.1 Summary of Water Standards

At present there are no specific Federal or state effluent regulations for Lurgi SNG facilities. The Federal Water Pollution Control Act (FWPCA; PL 92-500) and the Clean Water Act Amendments of 1977 (PL 95-217), however, authorize the U.S. EPA to establish effluent limitations and guidelines and new source performance standards for point source discharges into natural waters. The Effluent Guidelines Division of the U.S. EPA is currently revising the list of industrial categories for which effluent guidelines and limitations and new source performance standards are to be established. Pursuant to this effort,

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*The Federal guidelines for Lurgi and gasification plants(22) and the designs for the proposed commercial facilities assume that incineration results in nearly complete oxidation of oxidizable substances.

EPA is currently developing background information on synthetic fuel technologies, and it is possible that Lurgi SNG plants will be included in the revised industry category list for which new source performance standards will be established.

Two other water laws/standards which might impact effluent discharges from Lurgi SNG plants are: the 1974 Safe Drinking Water Act (SDWA; PL 93-523) and state deep well injection regulations. A brief discussion of the FWPCA, the Clean Water Act Amendments, state deep well injection laws and the SDWA follows.

FWPCA and the Clean Water Act Amendments. FWPCA, which is the most comprehensive water legislation ever passed by the Congress, is aimed at restoring and maintaining the integrity of the nation's waters. The Act directs EPA to develop and enforce standards for waste discharges into navigable waters and publicly owned wastewater treatment plants. It sets specific timetables for industry to achieve effluent limitations consistent with the application of the best practicable control technology (BPT) and best available technology economically achievable (BATEA). In addition, the Act directs the EPA to promulgate and enforce national standards of performance for all new sources and pretreatment standards for industrial discharges into publicly owned treatment plants and to control discharges of toxic substances. Section 402 of the FWPCA, National Pollutant Discharge Elimination System (NPDES), authorizes an EPA- or state-administered permit system for discharges to navigable waters. The permit for a point sources discharge will specify the materials, quantities to be discharged, discharge conditions and the monitoring and reporting systems to be used.

The scope of the FWPCA has been expanded by the passage of the 1977 Clean Water Act Amendments which places a greater emphasis on the control of toxic pollutants and establishes new deadlines for promulgation of and compliance with effluent regulations. Under the provisions of the 1977 amendments, the pollutants in industrial water discharges are divided into three categories, each with a specific level of control to be imposed by a specific date. First, there are "conventional" pollutants which include suspended solids, BOD, pH and fecal coliform.* The conventional pollutants are subject to "best conventional pollutant control technology" (BCT) with a deadline for achievement of July 1, 1984. Second are the "toxic" pollutants which include, at a minimum, the list of 65 substances/classes of substances* (referred to as the "priority" or the "consent decree" pollutants). These require best available technology economically available (BATEA) guidelines to be promulgated by EPA and applied no later than July 1, 1984. All other pollutants not identified as conventional or toxic are designated "non-conventional." They require BATEA with a dealline of three years after an effluent limitation is established or by July 1, 1984, whichever is later. The 1977 amendments also require that NPDES permits include limitations on the discharge of the priority pollutants.

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*EPA is considering the inclusion of oil and grease, COD and phosphorus in the list of "conventional" pollutants.

Constituents in Lurgi SNG plant wastewaters are expected to contain substances in all three pollutant categories. Most of the priority pollutants identified by EPA are organic compounds not generally expected to be present in effluents from Lurgi gasification plants. However, certain aromatic hydrocarbons (e.g., benzene, naphthalene, acenaphthylene) as well as phenols and trace elements which are included among the priority pollutants, are known or are likely to be present in aqueous wastes from Lurgi plants.

As noted above, at present no new source performance standards have been developed by EPA for the proposed Lurgi SNG plants. Also, since none of the proposed commercial Lurgi plants is to discharge wastewaters to publicly-owned treatment plants or to navigable waters, no permits have been applied for under the NPDES or the local regulations for discharges into municipal treatment plants. (Some effluent standards have been promulgated for a number of industries whose effluents may have certain similarities to Lurgi SNG plant wastewater. Examples of these industries are petroleum refining and by-product coke production. If Lurgi plants were to discharge effluent into navigable waters, effluent standards for such plants may have some similarities to the standards for these similar industries.)

Safe Drinking Water Act (SDWA) and State Deep Well Injection Regulations. Under Sections 1421 through 1424 of the SDWA, EPA is authorized to regulate underground injection to protect underground water sources. The regulation is done through the state programs which must be approved by EPA. The approval also qualifies the states for receiving grant funds to administer the program. EPA is also authorized to designate those states, U.S. territories and possessions which require underground injection control programs as a first step in the development of regulations for state underground injection control programs*(111).

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*The 65 substances/classes of substances are now expanded/subdivided into 129 substances/subclasses of substances.

Under EPA-promulgated regulations a waste can be injected underground if it can be demonstrated that: (a) the injection will not degrade the quality of any of the existing groundwater, or (b) the aquifer is not a potential source of drinking water (i.e., having more than 10,000 mg/l total dissolved solids). Because of the stringent nature of these restrictions, the practice of underground injection of industrial wastes has become less frequent in recent years. Even though one proposed commercial SNG plant (the ANG project) features underground injection for the disposal of certain small volume saline wastes, deep well injection is not expected to be used for the disposal of wastes from Lurgi gasification plants. If underground waste injection is to be used by Lurgi gasification plants, the state/EPA permit for such disposal would be issued on a case-by-case basis(112).

Additional regulations entitled "State Underground Injection Program Control Regulations," which will control deep well injections of wastes at the state level, are to be issued by EPA's Groundwater Protection Branch in draft form in early 1979(112). The thrust of the regulations is to insure that wastes are injected into strata that will not contaminate drinking water, and that all deep wells are designed, constructed and operated in an environmentally sound manner. Not all of the states receiving grants will be required to immediately implement the new regulations, although all must comply within 2 years from the date of issuance. EPA has designated 22 priority states, which must immediately comply with the new regulations, and which were selected based on the following considerations: (a) deep well injection is performed on a relatively large scale within the state, and (b) the potential for contamination of drinking water supplies is higher due to existing hydrological and geological conditions in the state.

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*A number of states, including Texas and Ohio, have had specific regulations for underground waste disposal even before the passage of the SDWA. These regulations have placed varying degrees of restriction on the practice of deep well injection. For example, Idaho and Arizona strictly prohibit waste disposal by deep well injection. In Texas permits for deep well injection are issued on a case-by-case basis.

The 22 priority states include several which are candidate locations for Lurgi's SNG facilities including Colorado, Illinois, Indiana, Kentucky, New Mexico, Ohio, Pennsylvania, Texas and Wyoming. Alabama, Montana, North Dakota, and West Virginia, which are also candidate locations, are not among the 22 EPA-designated priority states(112), and would not be required to immediately adopt the regulations.

5.3.2 Comparisons of Waste Streams with Effluent Standards

As noted in Section 5.3.1, at the present time there are no effluent standards for discharges from Lurgi SNG facilities. The Effluent Guidelines Division of EPA is now in the process of evaluating background data on coal gasification and other new energy technologies to determine the necessity and schedule for developing guidelines for these industries. If the few proposed commercial Lurgi SNG plants are representative of the Lurgi facilities which would be actually built and operated, such facilities would have no direct discharge to surface waters and any effluent standards for such plants would specify no discharge. At the present time there are insufficient data on both the characteristics of the wastewaters from Lurgi SNG plants and on the capabilities of the proposed controls to adequately evaluate the economic and environmental impacts of regulations requiring zero discharge.

As it has been proposed for at least one of the proposed Lurgi SNG plants, deep well injection may be used for the disposal of certain wastes. Standards for such disposal are set on a case-by-case basis and would depend on the characteristics of the receiving formation and the particular waste to be injected.

5.3.3 Impacts on Ambient Water Quality

If Lurgi SNG plants are to have no direct discharges to surface waters, no direct impacts on the ambient water quality are anticipated. Such plants, however, may have "indirect" impacts on the quality of the surface waters and groundwaters due to extensive water withdrawals, possible intermedia transfer of pollutants or accidents and system failures. The impacts of heavy water withdrawals on the quality of surface water and groundwater supplies are discussed in Section 5.8. The intermedia pollution transfer routes may include percolation of wastewaters from impoundments and leachates from landfill/mines, uncontrolled runoff from plant sites and precipitation "washout" and "fallout" of air pollutants from the facility. The indirect impacts on ambient water quality can be minimized through proper plant siting and proper design and operation of landfills, impoundments, air pollution control systems, and run-off containment measures.

5.3.4 Evaluation of Unregulated Pollutants and Bioassay Results

As noted previously, there are currently no effluent regulations covering discharges (if any) from Lurgi SNG plants. Further, as currently envisioned, commercial SNG plants are not expected to have any direct discharges to surface waters. Hence, any hazard associated with "regulated" or "unregulated" pollutants in Lurgi wastewaters would be in connection with indirect discharges. Because of the lack of composition and bioassay data on potential indirect discharges (e.g., landfill leachate and pond percolation) and the site-specific/plant-specific nature of such discharges, the degree of hazard created by any such discharges cannot be evaluated at this time.

5.4 IMPACTS OF LAND DISPOSAL

5.4.1 Summary of Land Disposal Standards

Although there are currently no specific Federal or state regulations for the management of solid wastes from Lurgi SNG plants, a number of general Federal/state solid waste disposal, resource recovery and reclamation acts are in effect which would impact solid waste generation treatment and disposal at Lurgi plants. The two most important of these acts are Resource Conservation and Recovery Act (RCRA) of 1967 (PL 94-580) and the Surface Mining Control and Reclamation Act (SMCRA) of 1977 (PL 95-87). These acts are briefly described below.

Resource Conservation and Recovery Act(114) (RCRA). The overall objective of this act is to provide for "technical and financial assistance for the development and management plans and facilities for the recovery of energy and other resources from discarded materials and for the safe disposal of discarded materials and to regulate the management of hazardous waste." The hazardous waste management provisions of this act, which would have greatest bearing on the management of the waste generated by industry, covers generation, transportation, storage, treatment/disposal and reporting requirements for hazardous wastes. Section 3001 of the Act directs EPA to identify which wastes are hazardous and in what quantities, qualities, concentrations and forms of disposal they become a threat to health or the environment. Section 3001 also requires

EPA to promulgate criteria and test procedures to be used in determining whether or not a waste is hazardous.

Wastes classified as hazardous would be subject to subsequent provisions of RCRA. Section 3002 requires EPA to issue hazardous waste handling procedures to be implemented by generators of hazardous waste, including record keeping and labelling practices, and use of a manifest system to assure that the waste is designated for proper treatment, storage and disposal. Section 3003 governs the establishment of standards which are applicable to hazardous waste transporters. Section 3004 establishes standards which are applicable to owners and operators of hazardous waste treatment, storage and disposal facilities; and Section 3005 establishes permits for the treatment, storage and disposal of hazardous wastes. The implementation of the regulations promulgated under RCRA is the responsibility of the individual states. Section 3006 directs EPA to provide guidelines to assist states in the development of state hazardous waste programs.

EPA has published proposed criteria for defining hazardous wastes(114). Under the proposed criteria waste would be considered hazardous if (a) it meets criteria for ignitability, corrosivity, reactivity or toxicity, or (b) it is one of the specific wastes in the EPA list of hazardous wastes and waste sources. Procedures have been proposed for the determination of ignitability, corrosivity, reactivity and toxicity of a waste. The test for toxicity consists of a "toxic extraction procedure." A waste would be considered toxic under the EPA proposal if an extract, as obtained through a defined extraction procedure, contains one of 14 contaminants above a specific level. These contaminants are arsenic, barium, cadmium, chromium, lead, mercury, selenium, silver and specific pesticides. The specified concentration levels for this substance in the extracts are ten times the National Interim Primary Drinking Water Standards. EPA intends to revise and expand the list and is considering use of the water quality criteria under the Clean Water Act as the basis for setting standards in addition to the drinking water standards.

The EPA list of specific wastes and waste sources (the second criteria for defining whether or not a waste is hazardous) cover 18 specific types of wastes (e.g., waste non-halogenated solvents, leachate from hazardous waste landfills, etc.) plus wastes from 130 categories of processes (e.g., distillation residues from the fractionation of benzene or chlorobenzene, petroleum refining, API separator and dissolved air flotation sludge, etc.).

None of the major solid wastes generated at a Lurgi SNG facility (e.g., gasifier and boiler ash, FGD sludges, spent catalyst) are on the EPA list of hazardous waste and waste sources. However, based on the toxic extraction criteria, some of these and other wastes produced at a Lurgi plant may be classified as hazardous, in which case the production, storage, transportation, treatment and disposal of such wastes would be subject to the regulations promulgated under RCRA.* Since (a) the limited information available on coal ash and FGD sludges indicate that these wastes present a relatively low hazard and (b) control techniques which might be applicable to other types of hazardous wastes might not be practical for the management of these wastes (because of the large volume of the waste generated in the utility industry), EPA has proposed to classify such wastes as "special wastes" subject to special regulations which will be promulgated at a later date. The gasification and boiler ashes produced in a Lurgi SNG plant would most likely be covered by such "special regulations."

Pursuant to the regulations proposed under Sections 3002 and 3004, a Lurgi SNG plant would be classified as a hazardous waste generator and as an owner/operator of a hazardous waste treatment, storage and disposal facility and must comply with applicable regulations. The proposed regulations for the hazardous waste generators require reporting/record keeping and compliance with DOT shipping, labelling and containerization practices. Regulations proposed under Section 3004 covers criteria for site selection, contingency/emergency procedures, record keeping/reporting procedures, closure and post closure, and groundwater and leachate monitoring. Standards are also proposed for storage and for treatment and disposal utilizing incineration; landfills; basins and surface impoundments; land forming; chemical, physical and biological treatment facilities; and resource recovery. Under Section 3005, owner/operators of facilities for the treatment, storage or disposal of hazardous wastes would require a permit (to be issued by state/EPA) which defines conditions for acceptable operation.

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*DOE recently launched a major nationwide assessment of the cost impact of RCRA regulations on conventional and advanced coal use technologies, including gasification(115). DOE and ASTM have also begun a 3-month effort to analyze the EPA toxic extraction procedure since it is feared that test results may warrant the classification of all coal ash and combustion residues as toxic. It is hoped that test results will be available by March 15, 1979, in time to provide comments on EPA's proposals under RCRA(116).

Section 8002 of RCRA requires EPA to conduct a detailed study of solid wastes from surface and underground mines and sludges/solid wastes from the gasification of coal and prepare recommendations for Federal and non-Federal actions regarding their environmental impacts. This study is currently under way.

Surface Mining Control and Reclamation Act (SMCRA). As was discussed in Section 4.4, disposal of solid wastes from Lurgi SNG plants in surface mines is an attractive solid waste management option and has been featured in the designs for the proposed commercial Lurgi SNG facilities. Since such disposal will be integrated with the mining and mine reclamation activities, it will be affected by certain provisions of SMCRA.

The overall objective of SMCRA is to protect the environment from the adverse effects of surface coal mining operations while assuring an adequate coal supply for the nation's energy needs and protecting the landowners near the operation. The act also provides for reclamation of the mined areas to a condition capable of supporting the uses which were capable of supporting prior to mining or to higher or better uses. Section 508 of the act requires submission for Federal/state approval of a reclamation plan as part of a request for the mining permit. Section 515 of the Act requires that the reclamation effort insure that all debris, acid forming materials, toxic materials or materials constituting a free hazard are treated or buried and compacted or otherwise disposed of in a manner designed to prevent contamination of ground and surface waters.

As with other Federal environmental laws, implementation of SMCRA is the responsibility of the states, with assistance from the Federal government. Under SMCRA authorization, an Office of Surface Mining and Enforcement (OSME) has been created in the Department of the Interior to review and approve the state programs and to provide guidelines to states in developing and enforcing regulations. OSME is also currently in the process of writing final regulations pertraining to strip mines and air quality. Interim regulations, which were issued in September 1973 would require mine operators to closely monitor their operations for both dust and coal particles(117).

5.4.2 Comparisons of Waste Streams with Disposal Standards

Based on the criteria proposed under RCRA for the definition of hazardous wastes, some of the solid waste streams generated at a Lurgi SNG plant would be classified as hazardous wastes. These waste streams, which are primarily the spent catalyst and oily and biological sludges, would be subject to the storage, transportation and treatment/disposal regulations which have been proposed by EPA and which are expected to be promulgated (perhaps with some changes) in the near future. It should be noted that these hazardous wastes account for a very small fraction of the solid wastes generated at a Lurgi SNG plant. The bulk of the solid wastes generated in a Lurgi SNG plant are the gasifier and boiler ash and, depending on the air pollution control processes employed, FGD sludges. Assuming that the gasifier ash would be considered similar to the boiler ash, these wastes would be subject to "special standards" which EPA proposes to promulgate for utility and other relatively high-volume and low-hazard industrial wastes.

5.4.3 Evaluation of Unregulated Pollutants and Bioassay Results

The solid wastes generated in a Lurgi SNG plant would be subject to the hazardous waste "special waste" regulations to be promulgated under RCRA. Even though the Lurgi gasifier ash may fall into the "special waste" category, there are some chemical composition and bioassay data (see Section 3.7.2) for the ash leachate which indicate that the Lurgi ash may be hazardous. This information and the results of other related on-going and planned studies (see Sections 3.1 and 6.2) would impact the promulgation of standards for the disposal of this particular waste.

5.5 PRODUCT IMPACTS

5.5.1 Summary of Toxic Substances Standards

Since the product SNG and some of the by-products produced in a commercial Lurgi SNG plant contain potentially toxic substances, the presence of such material in a work environment and their distribution in commerce would be subject to the provisions of the Occupational Safety and Health Act (OSHA; PL 91-506) and the Toxic Substances Control Act (TSCA; PL 94-469). A brief description of the pertinent sections of these acts follows.

Occupational Safety and Health Act (OSHA). This act authorizes the U.S. Department of Labor (DOL) to set mandatory standards to safeguard the occupational safety and health of all employers and employees of businesses engaged in interstate commerce. The act specifically authorizes the regulation of toxic materials, and requires the DOL secretary to "set the standard which most adequately assures ... that no employee will suffer material impairment of health or financial capacity" due to regular exposure to toxic substances and other occupational hazards.

Among the standards which have been promulgated to date under OSHA are those pertaining to worker exposure to toxic and hazardous air contaminants. These standards consist of ceiling and peak concentration, time-weighted average limits and/or threshold limit values for over 500 toxic organic and inorganic compounds which include many of those identified in Section 3.4 as potential constituents of Lurgi SNG and by-products. Table 5-14 lists OSHA standards for some of the materials which are known or expected to be present in a Lurgi coal gasification plant.

Under the authority of OSHA, regulations have been promulgated relating to exposures to some 17 occupational carcinogens. The regulated carcinogens are(118): asbestos, 4-nitrobiphenyl, alpha-naphthylamine, 4,4'-methylenebis-(2-chloroaniline), methyl chloromethyl ether, 3,3'-dichlorobenzidine (and its salts), bis-chloromethyl ether, beta-naphthylamine, benzidine, 4-aminodiphenyl, ethyleneimine, beta-propiolactone, 2-acetylaminofluorene, 4-dimethylamino azobenzene, N-nitrosodimethylamine, vinyl chloride, coke oven emissions, 1,2-dibromo-3-chloropropane and acrylonitrile. Except for asbestos, vinyl chloride and coke oven emissions for which the standards are based on concentrations in ambient air (2 fibers longer than 5 μ/cm^3, 1 ppm and 150 Ng/m^3, respectively), the standards for the regulated carcinogens are for products containing 0.1% or 1% or more by weight or volume of the regulated substance. When these concentrations are exceeded, the OSHA regulations prohibit the use/storage of such products in open vessels and require strict adherence to appropriate industrial hygiene practices.

The National Institute of Occupational Safety and Health (NIOSH) has published a list of suspected carcinogens covering some 1500 chemical substances.

TABLE 5-14. OSHA STANDARDS FOR MATERIALS KNOWN OR SUSPECTED TO BE PRESENT IN LURGI SNG PLANTS(121)

Compound	TWA,* ppm	TWA,* mg/m^3	Acceptable Ceiling Concentration	Where Found
Acetic acid	10	25	--	Gas stream, gas liquor
Ammonia	50	35	50	Gas stream, gas liquor
Aniline (skin)	5	19	--	
Antimony	--	0.5	--	Trace element in coal
Arsenic	--	0.5	(.002 mg/m^3)	Trace element in coal
Benzene	10(1)	--	25 ppm	Gas stream, naphtha
Beryllium	--	0.002 (0.002)	005 mg/m^3	Trace element in coal
Butyl mercaptan	10	35	--	Gas stream, naphtha
Cadmium (dust)	--	0.2 (.04)	0.6 mg/m^3 (0.2 mg/m^3)	Trace element in coal
Carbon dioxide	5000 (10,000)	9000 (18,000)	(30,000 ppm)	Gas stream
Carbon disulfide	20(1)	--	30 ppm (10 ppm)	Gas stream
Carbon monoxide	50(35)	55	(200 ppm)	Gas stream, product SNG
Carbon tetrachloride	10	1	25 ppm	Laboratory
Chromium, soluble salts	--	0.5 (0.025)	(0.05 mg/m^3)	
Chromium, insoluble salts	--	1	--	Trace element in coal
Coal dust (<5% SiO_2)	--	2.4	--	Coal preparation areas
(>5% SiO_2)	--	0.10	--	
Coal tar pitch volatiles†	--	0.2	--	Gas stream, tars, oils
Cresol (skin)	5	22	--	Gas stream, naphtha
Ethyl benzene	100	35	--	Gas stream, naptha
Ethyl mercaptan	--	435	10 ppm	Gas stream, naphtha
Hydrogen chloride	--	--	5 ppm	Stream
Hydrogen sulfide	--	--	20 ppm (10 ppm)	Gas stream
Hydrogen cyanide	10	--	25 ppm	Gas stream
Lead and inorganic lead compounds	--	0.2 (0.10)	--	Trace element in coal
Manganese	--	--	5 mg/m^3	Trace element in coal
Mercury	--	0.1 (0.05)	--	Trace element in coal
Methanol	200 (200)	260	--	Rectisol solvent
Methyl mercaptan	--	--	10 ppm	Gas stream
Naphtha (coal tar)	100	400	--	Gas stream, tars, oils
Naphthalene	10	50	--	Gas stream, tars, oils
Nickel carbonyl	0.001	0.07	--	Methanation areas, product SNG
Nickel metal and soluble compounds (as Ni)	--	1	--	Trace element in coal
Nitrogen dioxide	5(1)	9	--	Incinerated wastes, boiler flue gases
Phenol (skin)	5	19 (20)	(60 mg/m^3)	Gas and gas liquor
Propane	1000	1800	--	Gas stream
Pyridine	5	15	--	Gas stream, tars, oils
Selenium compounds	--	0.2	--	Trace element in coal
Silica (respirable)	--	0.10 (0.05)	--	
(total dust)	--	0.30	--	
Styrene	100	--	--	
Sulfur dioxide	5(2)	13	--	Incinerated wastes, boiler flue gases
Toluene	200 (100)	--	--	Gas stream tars, oils
Vanadium	--	(1)	(0.05 mg/m^3)	Trace element in coal
Xylene	100 (100)	435	--	Gas stream, tars, oils

*Time-weighted average. Numbers in parentheses indicate NIOSH recommended standards

†Coal tar pitch volatiles, as measured by the benzene-soluble fraction of particulate matter, includes such polycyclic aromatic hydrocarbons as anthracene, benzo(a)pyrene, phenanthrene, acridine, chrysene, and pyrene.

Some of the substances on the NIOSH suspected carcinogens list would be present in Lurgi SNG product/by-products and are subject to future regulations by OSHA.

Toxic Substances Control Act (TSCA). This act authorizes EPA to promulgate regulations for the control of substances or mixtures of substances which, in the judgment of EPA, present an unreasonable risk to health and to the environment through their manufacture, processing, distribution in commerce, use or disposal. Such regulations may prohibit the manufacture, processing, etc. of certain substances and impose restrictions on manufacture, processing, etc. of other substances. The act also directs EPA to issue regulations on testing, premarket notification, and for reporting and retention of information. Under Section 4 of TSCA, the EPA is empowered to conduct testing on suspected toxic substances to develop data with respect to the health and environmental effects for which there is an insufficiency of data and which are relevant to the determination of whether the manufacture, distribution, processing, use and/or disposal of the substances present a risk of injury to health or the environment.

To achieve the TSCA goals, EPA has identified and has begun actions toward achieving the following objectives: (1) definition of methods for assigning priorities to chemicals for investigation and regulation; (2) establishment of procedures for testing and evaluating hazardous chemicals; (3) establishment of mechanisms for premanufacture notification of new chemical substances; and (4) development of international approaches to toxic substances control(119). To date, EPA has developed a "chemical use list" for the purpose of industry reporting and EPA-decisionmaking regarding chemical manufacture, importing and/or processing(120). On October 26, 1978, the Interagency Testing Committee authorized under TSCA for chemical testing prepared for EPA a priority listing of chemicals to be considered for testing; TSCA requires EPA to respond to these recommendations within one year. The substances recommended for testing include: alkyl epoxides, alkyl phthalates, chlorinated benzenes, chlorinated paraffins, chloromethane, cresols, nitrobenzene, toluene and xylenes.

5.5.2 Comparisons of Product Characterization Data with Toxic Substances Standards

The implementation of TSCA is in initial stages and no substance-specific regulations have as yet been issued by EPA. However, since the product and by-products produced in SNG plants would contain certain toxic substances, it is very likely that Lurgi product and by-products be subject to future TSCA regulations. Such product and by-products, however, may subject the Lurgi SNG plants to OSHA regulations for the workplace ambient exposure. As noted in the previous section, OSHA regulations currently cover seventeen substances which have been labeled as occupational carcinogens. Although some of the regulated carcinogens (e.g., benzidine and naphthylamines) are expected to be present in Lurgi tars and oils, it is not envisioned that their concentrations would exceed those which would make the by-products subject to OSHA regulations.

Table 5-14 presents the OSHA ambient standards for workplace exposure to some of the substances which are expected to be found in Lurgi SNG plants. The presence of these substances in the ambient environment in a Lurgi plant may result from fugitive or evaporative emissions from various production, transportation and storage units and from accidental spills and equipment/system failure. For many of the substances listed in Table 5-14, OSHA standards are not expected to be exceeded under normal operating conditions primarily due to the closed nature of the Lurgi SNG systems. For some highly volatile substances such as benzene, evaporative emissions must be controlled in order to comply with the ambient standards.

5.5.3 Evaluation of Unregulated Toxic Substances and Bioassay Results

As noted above, no regulations have yet been promulgated under TSCA which is to control toxic substances in commercial products. In this regard, all toxic substances in Lurgi SNG product and by-products would be considered unregulated. The existing OSHA ambient regulations cover the majority of substances which are known to be present in Lurgi product and by-products. Since composition data are not available for such materials, it is possible that additional OSHA regulations may be developed in the future covering toxic substances not yet identified in Lurgi product and by-products.

No bioassay data are yet available to indicate toxicity of Lurgi product and by-products. Bioassay tests and epidemiological studies, however, have been conducted on coal-derived oils and tars produced by other coal conversion processes and in the by-product coke industry. Since these coal-derived products contain some of the substances which would be present in Lurgi tars and oils, the results of these bioassay and epidemiological studies may give some indications of the toxicity expected from Lurgi tars and oils. Several fractions of coal oils produced by the Bergius and Fischer-Tropsch processes have been tested for carcinogenicity, and the results have indicated that hydrogenated coal oils are carcinogenic and that carcinogenic potency resides in the heavy ends and higher boiling fractions. Tars produced in the coking of coals are established as chemical carcinogens; exposure to air-borne tar particulates are regulated under OSHA standards for occupational carcinogens.

In the 1950's Union Carbide Corporation conducted bioassay and industrial hygiene studies in connection with a coal hydrogenation plant at Institute, West Virginia(122). The work consisted of chemical analyses of a number of products and intermediate streams, bioassay experiments on mice, and epidemiological studies of plant workers and laboratory personnel exposed to coal hydrogenation products. Over 200 chemicals were identified in the coal hydrogenation process, some belonging to classes of compounds known to include carcinogens. Tests indicated that light oil stream (boiling below 260°C) and its derivatives were without tumorigenic action. The streams boiling at higher temperatures - middle oil, light oil stream residue, pasting oil, and pitch product - were all carcinogenic. For these streams, carcinogenic potency increased, and the length of the median latent period decreased, with the rise in boiling point. Protective clothing and personal hygiene procedures did not totally prevent skin cancer.

5.6 RADIATION AND NOISE IMPACTS

Radiation and noise are two additional potential categories of environmental problems associated with the operation of a Lurgi SNG plant. The radiation problem stems from the presence of radioactive substances in the coal; the noise problem is primarily due to the operation of process and mining equipment.

5.6.1 Radiation Impacts

Coals contain varying amounts of the naturally occuring radioactive isotopes of uranium, thorium, and their daughter products. The limited data available on the composition of the coals which are to be gasified in the proposed U.S. commercial Lurgi SNG plants were presented in Table 3-1. The data in this table indicated a U concentration of about 1 ppm for these coals. Table 5-15 presents data on the ranges of U and Th which may be found in other selected U.S. coals. As indicated by the data, the mean concentrations of U and Th in these coals

TABLE 5-15. URANIUM AND THORIUM CONTENTS OF COAL SAMPLES TAKEN FROM VARIOUS REGIONS OF THE UNITED STATES(123)

Region	Coal Rank	Number of Samples	Uranium Concentration (ppm)		Thorium Concentration (ppm)	
			Range	Geometric mean	Range	Geometric mean
Pennsylvania	Anthracite	33	0.3-25.2	1.2	2.8-14.4	4.7
Appalachia	Bituminous	331	<0.2-10.5	1.0	2.2-47.8	2.8
Interior	Bituminous	143	0.2-54	1.4	<3-79	1.6
Northern Great Plains	Subbituminous, lignite	93	<0.2-2.9	0.7	<2.0-8.0	2.4
Gulf	Lignite	34	0.5-16.7	2.4	<3.0-28.4	3.0
Rocky Mountain	Bituminous, subbituminous	134	<0.2-23.8	0.8	<3.0-34.8	2.0

Note: The arithmetic average concentrations of thorium and uranium in ppm for all coal samples and various ranks of coal for the whole United States are as follows:

Coal Rank	Samples	Thorium (ppm)	Uranium (ppm)
All coal	799	4.7	1.8
Anthracite	53	5.4	1.5
Bituminous	509	5.0	1.9
Subbituminous	183	3.3	1.3
Lignite	54	6.3	2.5

are in the 0.7 to 2.4 ppm and 1.6 to 4.7 ppm ranges, respectively. A few Northern Great Plains lignites have been reported to contain up to 200 ppm U, a concentration much higher than those reported in Table 5-15(124). It should be noted that the amounts of U and Th found in most coals are not greatly different than those found in many other types of common rocks (e.g., limestone, shale, granite)(125).

Based on the limited data available on the fate of U and Th in Lurgi gasification systems, it appears that these elements will largely be retained by the gasification ash. Small amounts of U and Th will be emitted to the atmosphere in particulate form from direct combustion of coal for onsite steam and power generation. Studies of coal-fired power plants, however, suggest that such emissions would not ordinarily represent a significant public health or ecological probem(123,126,127). U and Th contained in gasification and boiler ash from SNG plants may be mobilized via leaching from waste deposits in landfills/reclaimed surface mines or in settling/evaporation ponds. Studies of settling basins and landfills handling ash from coal-fired power plants suggest that U in ash can be mobilized at a rate larger than 10% of the natural weathering rate of rocks. Thus, unless the landfills and ponds which handle coal ash from Lurgi SNG plants are designed and operated to minimize leachate formation and/or contain leachate, a potential exists for intrusion of this element into ground and surface waters in amounts which may prompt concern.

5.6.2 Noise Impacts

Like most large industrial facilities, Lurgi SNG plants may be expected to have a number of sources of noise which would require control. Major noise sources would include crushers, screens and coal conveying systems; blowers and compressors; and cooling towers. Depending on the plant location in relation to the coal mine, mining operations (e.g., blasting, hauling, use of draglines) may also be major contributors to the noise problem from the mining/gasification complex. During the construction phase of an SNG plant noise associated with vehicles, jack hammers, pneumatic tools, scrapers, etc. would also be expected. Although no actual data are available on noise levels which would be encountered in an SNG facility, mitigating measures for noise control are available and are considered established practice in a number of other industries. Compressors and coal handling equipment would be located inside structures designed to minimize noise. Other equipment such as fans, blowers and burners can be designed to minimize noise by reducing turbulence and streamlining flow. The very "noisy portion" of the plant can be located in isolated areas or housed in acoustically insulated structures. Use of hearing protection devices would also be required for employees working in such areas.

It should be noted that noise associated with an SNG plant would not be unique to that type of operation but may be similar to noise from cement plants, coal mines, petroleum refineries, etc. Further, the proposed locations of Lurgi SNG facilities to date are in relatively unpopulated sites which would diminish exposure of large numbers of persons to plant noise, thus largely reducing the problem to one of industrial hygiene nature requiring in-plant control.

5.7 SUMMARY OF MAJOR ENVIRONMENTAL IMPACTS

5.7.1 Air Impacts

Lurgi SNG plants would be major point sources of emissions of sulfur compounds (primarily SO_2) and hydrocarbons and, to a lesser extent, of CO, NO_x and particulates. Most of the impacts on ambient air quality from an integrated Lurgi SNG facility are due to emissions associated with the use of coal for on-site steam and power generation rather than from gasification. Lurgi SNG plants which would utilize the control technologies consistent with those proposed by developers for commercial SNG plants or by EPA in its guidelines for Lurgi SNG facilities should meet the NAAQS for all criteria pollutants.* The PSD SO_2 increment for Class II region, however, may be exceeded if high sulfur coals are to be gasified. Although very limited information is available on non-criteria pollutant emissions from gasification plants, the proposed technologies appear adequate for the control of such pollutants. The results of one modeling effort has indicated the hydrocarbon and NO_x emissions from Lurgi SNG plants may lead to oxidant levels in excess of NAAQS.

5.7.2 Water Impacts

As was discussed in Section 5.3.3, the water impacts associated with at least the first generation Lurgi SNG plants would be primarily of an indirect nature since such facilities would most likely be operated with zero effluent discharge to surface waters. Any impacts on water quality would be of an indirect nature resulting from heavy water withdrawal (consumptive use), possible intermedia transfer of pollutants (e.g., contamination of surface and groundwater by leachates and seepage from landfills and evaporation ponds), or accidental spills and systems failure. The impact on water quality due to water withdrawal, which is an important consideration in the selection of plant site, is discussed in Section 5.8. Other indirect impacts are plant- and site-specific and can be minimized through proper design and operation of production and pollution control systems.

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*This does not take into account any additive particulate emissions from mining and coal preparation operations which may be conducted in the general vicinity of the gasification plant.

5.7.3 Impacts of Solid Wastes

The large volume solid wastes in a Lurgi SNG plant are the gasifier and boiler ash and FGD sludges (if throw-away FGD systems are used). In terms of quantity and characteristics, these wastes would be similar to those from an electric utility plant using the same amount of feed coal. The management of these wastes management practices would be essentially the same for Lurgi SNG and electric utility plants. The environmental impacts associated with the disposal of these high volume wastes are generally of an indirect nature and stem from potential mobilization of soluble components via leachate formation and seepage from containment sites. Such impact can generally be minimized by proper selection, design and operation of the disposal sites.

Smaller volume solid wastes at Lurgi SNG plants are spent catalyst, tarry/oily sludges and biosludges. Because of their more hazardous characteristics these wastes can have a greater potential environmental impact, unless properly handled and disposed of. The practice of hazardous waste management used in similar industries (e.g., petroleum refining and petrochemical production) would be applicable to the management of these wastes to reduce their impacts.

5.7.4 Impacts of Toxic Substances

The product SNG and by-products from Lurgi plants would contain potentially toxic substances. These toxic materials can have adverse impacts on plant workers and the general public. The adverse impacts are primarily due to fugitive emissions (leaks, evaporative emissions, etc. at plant site, during transport and at end-use facilities) and accidental spills and system/equipment failure. These impacts can range from acute toxic effects (e.g., inhalation of ammonia near the spill site) to chronic effects (e.g., potential for skin cancer due to long-range exposure of plant workers to Lurgi tars). Although some of the substances in Lurgi produce, by-product and waste streams are known to be toxic, detailed quantitative characterization data and bioassay results are not available for these materials to assess the degree of toxicity and safe exposure levels. Moreover, because of lack of plant operating experience, the extent of exposure that Lurgi plant workers would ordinarily experience cannot be estimated at this time. Any epidemiological data which may exist on foreign Lurgi facilities are not available to assist in the definition of health hazards in a Lurgi plant.

5.7.5 Other Impacts (Noise, Radiation, Land Use)

Even though the radioactive elements originally present in coals concentrate in the gasifier and boiler ash, the radioactive content of the ash from the majority of U.S. coals is not generally much higher than that for such common industrial materials as limestone, gravel, etc. The large-scale use of coal in Lurgi SNG plants thus is not expected to result in any signficiant increase in background radiation at the plant or waste disposal site or in radiation exposure levels for the general public.

As with most large-scale industrial facilities, some noise is expected from the operation of various equipment at a Lurgi SNG plant. The noise control practices used in other industries should be adaptable to Lurgi plants. The reduced off-site noise levels expected from the application of such controls cannot be quantified at this time.

The impact of land use associated with Lurgi plants is an element of the broader siting consideration which is discussed below.

5.8 SITING CONSIDERATIONS FOR GASIFICATION PLANTS

Major factors which should be considered in the comparative evaluation of alternative sites for a Lurgi SNG plant include: air quality considerations, hydrogeological factors, land use considerations and secondary impacts associated with population influx.

The air quality considerations primarily relate to the EPA air quality area designations and the local meteorological conditions. A Lurgi SNG plant cannot be located in a "nonattainment" area unless the emissions from such a plant can be offset through reductions in the emissions from other sources in the area.

Lurgi plants using high sulfur coals may not be located in "Class II" areas if the allowable "PSD" increment for Class II areas are likely to be exceeded due to the specific local meteorological conditions. Because of the very small PSD increment allowed for "Class I" areas, Lurgi plants cannot be located in these areas (without use of extensive additional pollution control). In addition to influencing whether a Lurgi SNG plant can meet PSD increment requirement for an air quality class, local meteorological conditions effect "visibility" which is an important aesthetic consideration for plant siting in scenic areas.

Hydrogeological conditions (specifically the distance to and the fluctuations in the groundwater table, the type and permeability of geological strata and soils, surface topography and precipitation pattern) are important siting considerations as they impact design, operation and cost of waste treatment and disposal systems (landfills, storage/evaporation ponds). When hydrogeological conditions are unfavorable, landfills and evaporation ponds must be lined and provisions must be made for collection and treatment of landfill leachate and pond leakage to reduce potential for the contamination of surface waters and groundwaters. When the cost for the protection of groundwater or surface waters at a site becomes economically unjustifiable, alternate plant or waste disposal sites should be investigated.

Even with the most effective water reuse and conservation measures, SNG facilities will be very large consumers of water. Such large volume consumption uses of water, especially when several plants are to be constructed in a given watershed, will reduce the availability of the groundwaters and surface waters for other uses and adversely affect the quality of such waters. This would be particularly true in the relatively arid west where water supplies are less abundant and there are existing water quality/quantity commitments (e.g., in the case of Colorado River water) to users in both the U.S. and Mexico.

Exclusive of the land which may be used at certain sites for evaporation ponds, Lurgi SNG plants by themselves would occupy only a very small land area (less than 40 hectares or 100 acres). Evaporation ponds can occupy several hundred hectares of land; however, such ponds would generally be used in plants in arid regions where large amounts of land having no competing land use values are available. In selecting a site for Lurgi SNG plants, the major land use issue pertains to the possible removal of land from other productive uses (e.g., agricultural production) for mining of coal to supply the SNG plants and for disposal of wastes. It should be noted that such land use impact is not unique to SNG plants and that which would be encountered in connection with large-scale mining of coal for other uses such as electric power generation and coke production.

As indirect land use impact associated with a Lurgi SNG facility is due to the influx of population created by the construction and operation of a Lurgi plant. Such population influx can create a host of indirect environmental problems which should be addressed in plant siting. Such environmental problems stem from increases in traffic and construction activities, and in demands for public utilities (water, electricity and sewage treatment) and services (schools, roads, housing, etc.).

6.0 SUMMARY OF NEEDS FOR ADDITIONAL DATA

At the present time there are no specific Federal standards for Lurgi SNG plants. In connection with (a) the development of EPA guidelines for the control of atmospheric emissions from Lurgi SNG plants and (b) various studies sponsored by EPA, DOE and process developers, a considerable amount of data have been generated pertaining to the environmental aspects of the Lurgi technology.

Despite their considerable volume, there are a large number of gaps in these data which would have to be filled in order to establish the data base needed for the development and enforcement of standards for Lurgi SNG plants and for defining health effects and control technology R&D needs. Some of the more important gaps in and the limitations of the existing data base have been pointed out in the preceding chapters of this report. This chapter presents a summary of the data needs and a brief review of the on-going environmental assessment programs which may provide some of the needed data.

6.1 DATA NEEDS

6.1.1 Data Needed to Support Standards Development and Enforcement

The data needed for setting and enforcing standards for Lurgi SNG plants relate primarily to (a) the characteristics (including health and ecological effects properties) of individual and combined waste streams, key process streams and product/by-products, (b) capabilities and costs of the available control technologies for SNG service and of alternative control options for pollution control at integrated facilities, and (c) instrumentation, sampling and analytical protocols and record keeping and reporting procedures. The waste/process stream and product/by-products characterization data are needed to establish the presence and levels of criteria/priority pollutants and other substances in the waste streams requiring regulations. The data on the capabilities of control technologies are needed for setting standards consistent with the application of the best control technologies economically achievable.

venturi scrubbing for particulate removal, Phenosolvan for recovery of phenols from wastewaters, sour water stripping for NH_3/H_2S removal and trickling filters for biological treatment), the various air, water and solid waste control processes which would be potentially employed at commercial facilities have not been used in Lurgi coal gasification applications. Even for the few processes which have been used for coal gasification, very little data are available on the characteristics of the treated streams and on the performance and costs of these applications.

In addition to the data needs pertaining to waste stream/control technology characterization (Tables 6-1 through 6-3), data are also needed on the composition of certain key process and product/by-product streams and on the fate of certain environmentally important constituents of the process streams in various Lurgi process/pollution control units. Key process streams which require more detailed characterization are "cooled" and shifted product gas. Although some data are available on the major constituents of these streams, the data on environmentally significant constituents such as carbonyl sulfide, mercaptans, hydrogen cyanide, volatile trace elements, and organometallics are insufficient to determine the fate of these constituents in the downstream processing units and hence, the pollution control needs. Based on the limited tests at the Westfield, Scotland plant, the Lurgi SNG product gas may contain $Ni(CO)_4$ (and possibly other trace toxic organometallic substances). If such substances are found in the product gas from commercial plants in significant concentration, the production, transportation and commercial uses of Lurgi product SNG would be subject to possible regulations under the Toxic Substances Control Act (TSCA). Based on the data from Westfield plant and from other gasification processes, Lurgi by-products (specifically tars, oils, naphtha and phenols) may contain traces or significant quantities of a host of toxic substances including benzene, aromatic amines and polynuclear aromatic hydrocarbons and heterocyclics, which may make them subject to TSCA regulations. Better characterization data including bioassay information are needed on the Lurgi product SNG and by-products to determine the necessity and type of regulations required.

Determining compliance with any standards which would be promulgated for Lurgi SNG plants would require the availability of suitable methods for measurement of pollutants in waste streams and product/by-products and of operating parameters. Based on the experience in standards setting for other industries,

TABLE 6-1. DATA NEEDS RELATING TO GASEOUS WASTE STREAM CHARACTERISTICS AND CONTROL TECHNOLOGY CAPABILITIES

Waste Stream	Waste Characteristics	Control Technology Capabilities
Coal crushing and screening off-gas	No data available on the quantity and characteristics (e.g., Level 1 analytical data) of dust from coal preparation for use in Lurgi plants.	The control technologies used in coal preparation plants should be applicable to Lurgi plants; emission standards exist for this source category.
Feed lockhopper vent gas	The quantity and characteristics (e.g., Level 1) are not available for these gases.	The need for and the effectiveness of incineration/particulate control not defined.
Ash lockhopper vent gas and ash quench off-gas	Same as for feed lockhopper vent gas.	The particulate control requirement (if any) not defined.
Concentrated acid gases	Limited composition data available for off-gas from certain Rectisol designs. These data do not cover all constituents of interest (e.g., HCN, COS, mercaptans) and are not reflective of Rectisol designs which will be employed in SNG service. This stream is expected to be the major gaseous waste stream in a Lurgi plant.	The cost and effectiveness of Claus and Stretford processes for the control of Rectisol off-gases containing high CO_2 levels and minor constituents such as HCN and COS.
Catalyst decommissioning/ regeneration off-gases	Same as for feed lockhopper vent gas.	Control technology requirements not established.
Depressurization and stripping gases	Limited data on major constituents based on the operation of foreign Lurgi plants. More detailed characterization (e.g., Level 1) data necessary.	The cost-effectiveness of control options (incineration vs. combining with the Rectisol gases for treatment) not evaluated.
By-product storage vent gases	Same as for feed lockhopper vent gas.	Control technologies used in petroleum refinery and other industries should be applicable to Lurgi plants; standards promulgated for the petroleum refining industry would probably be extended to cover the synthetic fuel industry.
Oxygen plant vent gases	Waste streams not expected to contain substances requiring regulations.	No controls likely to be necessary.
Transient waste gases	Same as for feed lockhopper vent gas.	The effectiveness of incineration (alone or in conjunction with fuel combustion) and the possible need for sulfur and hydrocarbon removal not known.
Fugitive emissions	Specific sources and emission characteristics in an actual plant not known.	Same as for by-product storage vent gases.
Sulfur recovery tail gas	No data available on waste characteristics from a Lurgi SNG plant application.	The effectiveness and costs of control options (incineration, incineration in combination with fuel gas combustion/FGD systems, and use of catalytic reduction processes such as Beavon) not established.
Flue gas from onsite steam power generation	Combustion flue gases are generally well characterized; EPA and other agencies have a number of on-going flue gas characterization programs.	Controls applicable to utility and industrial boilers would generally be applicable. Established emissions regulations would cover boilers at Lurgi plants.

TABLE 6-2. DATA NEEDS RELATING TO AQUEOUS WASTE STREAM CHARACTERISTICS AND CONTROL TECHNOLOGY CAPABILITIES

Waste Stream	Waste Characteristics	Control Technology Capabilities
Coal pile runoff	No data on characteristics and quantities for a Lurgi SNG plant(this stream would be coal- and site-specific). Limited data available for waste stream at electric utility plants.	Runoff diversion and containment techniques are well established from other industries and should be applicable to Lurgi plants.
Ash quench slurry	Limited data available on elemental composition and leaching potential of unquenched ash from the gasification of a few American coals. No data available on coals proposed for actual use in U.S. plants and for conditions when process waters (e.g., clean gas liquor) are used for ash quenching.	Slurry transport, solids settling/dewatering technology from utility industry should be directly applicable. Capabilities of technology in terms of characteristics of clarified ash slurry water not known.
Raw gas liquor	Limited data available on major constituents and gross parameters, trace elements and a few specific organic compounds for certain feed coals. No comprehensive characterization data (Level 1 testing) on the organics. No data available reflective of coals proposed for actual use in U.S. plants.	Capabilities of tar/oil separation, Phenosolvan, and ammonia recovery well established in terms of removal of major constituents. Capabilities for removal of minor constituents not established. Limited cost data available on processes.
Clean gas liquor	Same as for raw gas liquor; limited data available on constituents biodegradability.	No data available on performance or cost of biological treatment or on problems associated with use as cooling tower or ash quench water makeup.
Rectisol methanol/ water still bottoms	Data available on major constituents and parameters from a foreign facility; comprehensive data (Level 1 results) not available. No data available for American coals or for Rectisol designs envisioned for use in U.S. SNG plants.	This small-volume stream would likely be treated in conjunction with clean gas liquor (see above).

(continued)

TABLE 6-2. CONTINUED

Waste Stream	Waste Characteristics	Control Technology Capabilities
Phenosolvan filter backwash	No data available on quantities, characteristics or generation frequency.	This small-volume stream would likely be treated with other plant wastewaters (e.g., plant runoff or ash quench slurry).
Boiler blowdown	Characteristics well known and not unique to Lurgi.	This relatively "clean" stream would like likely be used as process water; no specific control technology data needs can be identified.
Cooling tower blowdown	Effect of using various process waste streams (e.g., clean gas liquor or Rectisol methanol/water still bottoms) as cooling tower makeup on the composition of the blowdown not established.	A likely treatment method would involve use as ash quench slurry water; impacts on the quench system and subsequent treatment of clarified water not established.
Waste sorbents and reagents	No data available for composition and quantities from applications in a Lurgi plant. Limited characterization data available on major constituents of certain wastes (e.g., Stretford and Wellman-Lord solution purges) from applications in other industries.	Applicable controls (e.g., resource recovery, disposal in lined pond, dissolved solids removal, deep well disposal, etc.) are waste-and site-specific; cost and performance data should be developed on a case-by-case basis.
Miscellaneous plant wastewaters (run-off, sanitary wastes, etc.)	Same as for Phenosolvan filter backwash.	The option control method (e.g., treatment and use as process water vs. treatment and discharge) not evaluated.
Combined plant effluent	No data available.	The effectiveness and costs of various applicable controls (e.g., solar or forced evaporation, physical-chemical treatment for water reuse, etc.) not determined.

TABLE 6-3. DATA NEEDS RELATING TO SOLID WASTE STREAM CHARACTERISTICS AND CONTROL TECHNOLOGY CAPABILITIES

Waste Stream	Waste Characteristics	Control Technology Capabilities
Coal fines, dust and refuse	No data available on characteristics and quantities for a Lurgi SNG plant (these wastes would be coal- and site-specific). Some data available from other industries (e.g., electrical utility and coking).	Control technologies (e.g., disposal in ponds/landfills) should be applicable. Effectiveness for containment and costs not evaluated.
Gasifier and boiler ash	No data available on quenched gasifier ash (including its hazardous characteristics). Limited data available on elemental composition and leaching potential of the unquenched gasifier ash for certain coals (not including those proposed for use in U.S. Lurgi plants) Boiler ash characteristics would not be unique to Lurgi, except when Lurgi process water is used for ash quenching.	Control technologies requirements dependent on forthcoming RCRA regulations; if these wastes are classified as "hazardous," existing controls used in utility industry may not be adequate and more effective controls (e.g., containment in secure landfills, lined ponds, fixation, etc.) may be required. Design criteria would have to be developed for these more stringent controls.
Spent catalysts and methanation guards	No characterization data (including hazardous characteristics) available on spent shift and methanation catalysts and methanation guards for Lurgi plants; very limited gross characterization available on spent methanation catalyst from pilot scale tests in connection with other gasification processes.	Control technologies used or proposed under RCRA for use in other industries (resource recovery, encapsulation and/or disposal in secured landfills) should be applicable. Although catalyst manufacturers/reclaimers may have costs and effectiveness data on these controls, such data are not publicly available.
Tarry/oily sludges	No data available on quantities and characteristics (including hazardous properties).	Control technologies used or proposed under RCRA for use in other industries (e.g., energy recovery, disposal in secure landfills) should be applicable; cost and effectiveness of these controls not defined.
Biosludges	No data available on quantities and characteristics (including hazardous properties).	Same as for tarry/oily sludges.
Inorganic solids and sludges (FGD wastes)	Data available on composition and handling/disposal characteristics (compactability, permeability, leachability) for FGD sludges from utility industry. Characteristics of FGD wastes are coal- and process-specific.	Same as for gasifier and boiler ash.

As with the standards for other industrial source categories, standards for Lurgi SNG plants should be in a format and contain numerical limits which are consistent with the available field data monitoring/analytical capabilities and do not place undue burdens on the industry for collection/submission of data.

Tables 6-1 through 6-3 summarize the specific data gaps and needs pertaining to the characterization of waste streams and definition/evaluation of applicable control technologies in Lurgi SNG plants. In general, the identified data gaps fall into two categories: (1) total non-existence or unavailability of the data, and (2) data which are available lack comprehensiveness or have been obtained under conditions significantly different than those anticipated in an integrated commercial Lurgi SNG plant in the U.S. Examples of data gaps in the first category are the lack of detailed characteristics data on emissions associated with decommissioning of spent methanation catalyst, on combined plant effluent and on sludges resulting from the treatment of such effluent or from the treatment of tarry/oily wastewaters. Since no integrated Lurgi SNG facility currently exists, this type of data is not available from actual operations to check the reasonableness of the estimates which are the basis for the proposed designs for commercial Lurgi SNG plants. In the case of emissions from catalyst decommissioning, even though some data might exist, such data are not publicly available due to proprietary considerations.

Examples of the second category of data gaps and limitations are the lack of trace element and organics data and toxicological and ecological characteristics data for various waste streams in a Lurgi SNG plant and data on the performance of various control systems in Lurgi SNG service. In general, the limited available waste characterization data do not cover organic and trace element constituents, bioassay information, waste treatability and characteristics such as non-biodegradability, health effects and potential for bioaccumulation and environmental persistence. For the Stretford and Beavon processes, which have been used in refinery and/or by-product coke applications for H_2S removal from acid gases containing relatively low levels of CO_2, limited commercial experience exists with acid gases containing high levels of CO_2 which would be encountered in a Lurgi SNG plant. With the exception of a few pollution control processes (e.g., flaring for hydrocarbon and H_2S control, some standards call for the use of specific equipment (e.g., flares and vapor recovery systems) rather than pollutant emission limits due to unavailability of suitable measurement methods. In recent years considerable work has been funded by EPA and other agencies to develop sampling and analytical protocols for the determination of criteria and priority pollutants in industrial process/waste streams. These protocols cover many but not all of the substances which are expected to be present in Lurgi SNG plant process/waste streams. In addition, some modifications to certain of these protocols may be required for application to specific conditions encountered in Lurgi SNG plants (e.g., high temperature/pressure gases, gases containing condensable organics or effluents containing substances which may interfere with the analytical determinations). Although efforts to define sampling and analytical support requirements for enforcement of standards generally go hand in hand with those for standard setting, the more exact definition of such support requirements should follow a clearer definition of the waste characteristics and of substances to be regulated.

6.1.2 Data Needed to Support Effects and Control Technology R&D

Some of the data identified above as being needed to support standards development and enforcement activities would have to be generated through R&D programs in the areas of health and ecological effects and evaluation and control technology development. Through such R&D programs, reliable data must be generated on performance and cost of control technologies and on health and ecological effects of wastes and products/by-products to uphold environmental standards and regulations as they are critiqued through the legal system. In addition to supporting the standards development and enforcement mandates of EPA, R&D programs in the subject areas are needed in connection with the EPA responsibility for assessing, developing and verifying methods for control of pollution from energy-related (and industrial) sources. The control technology and health and ecological R&D needs which are specifically related to or have some bearing upon the Lurgi SNG systems are briefly reviewed below.

- Gathering and analyzing existing process and environmental data on Lurgi SNG systems. This document represents the most updated compilation and analysis of the existing information on Lurgi SNG systems. Considerable additional data are expected to become available as a result of on-going or planned programs. This document must be updated periodically to incorporate additional data as they become available and to provide a basis for reexamination of problems and R&D needs.

- Multimedia environmental sampling and analysis. As was discussed in Section 6.1.1, although some characterization data are available on certain Lurgi process/waste streams, such data are not comprehensive in that not all streams or process conditions are addressed and not all potential pollutants and toxicological/ecological properties are defined. Some of these data gaps can be filled through chemical/biological testing of process effluents at existing facilities. Although no Lurgi SNG facilities currently exist and foreign Lurgi facilities do not incorporate all units and design features of a commercial Lurgi SNG plant, sampling and analysis at foreign Lurgi sites provide the best and only currently available means of acquiring certain process and environmental data for Lurgi systems. Additional data can be collected through sampling and analysis of Lurgi system components used in other coal conversion and industrial applications (e.g., the Rectisol, Stretford and methanation processes).

- Health and ecological effect support studies. The comprehensive environmental assessment of Lurgi SNG systems require information on health and ecological properties of product/by-products and waste streams from such systems. Some of this information (e.g., presence and levels of specific toxic substances in various streams, and bioassay data) would be generated as part of environmental sampling and analysis. Other information relating to parameters such as bioaccumulability, environmental transport and fate and synergistic effects would have to be obtained through separate studies. The health and ecological support studies and the data from sampling and analysis effort provide the necessary input for the definition of multimedia environmental goals (MEG) for substances/parameters of interest associated with Lurgi systems and for assessing health hazard and ambient environmental impacts using source analysis models (SAM).

- Assessment of the cost and effectiveness of various candidate control processes, treatment schemes and waste management options for application to Lurgi SNG systems. As discussed in Section 6.1.1, many of the controls which would be potentially applicable to the management of Lurgi waste streams have not been tested in Lurgi service or in similar industrial applications. R&D programs should include the pilot or bench-scale testing of control processes/treatment schemes on Lurgi streams. Such studies may be conducted onsite (e.g., at foreign Lurgi facilities and at plants in similar industries) or offsite using samples from such plants or from pilot/bench-scale units simulating conditions in Lurgi systems. The pilot- and bench-scale testing should be supplemented by engineering analysis to estimate the costs and evaluate applicability of controls for use in integrated SNG plants

- Miscellaneous support activities. These activities, which would be primarily in support of the above areas of environmental assessment and control technology R&D, may include development of sampling and analytical methodology, techniques for defining when and which more costly detailed analysis is needed, improvement to existing SAM's and development of more comprehensive models for source assessment, coordination of related R&D activities sponsored by various governmental agencies and the private sector and dissemination and exchange of information through the holding of symposia, conferences, etc.

6.2 DATA ACQUISITION BY ON-GOING ENVIRONMENTAL ASSESSMENT ACTIVITIES

The on-going programs, which are expected to provide some of the needed data identified in Section 6.1, fall into three categories: EPA-sponsored programs, DOE-sponsored programs and miscellaneous programs. The most pertinent of the EPA- and DOE-sponsored programs are listed in Tables 6-4 and 6-5, respecitvely. Mostly due to proprietary considerations, very limited data are available on the programs in the miscellaneous category which are primarily carried out by or under funding from the Lurgi corporation, sponsors of proposed commercial Lurgi SNG projects and other private firms/organizations.

The most pertinent data-acquisition program in the EPA-sponsored category is the multimedia sampling and analysis effort currently under way at the Kosovo Kombinant plant in Yugoslavia. This program is the most comprehensive environmental data acquisition effort ever undertaken at a Lurgi facility. Although not an SNG plant, the Kosovo Lurgi facility, which produces medium Btu gas and hydrogen for ammonia production, features many of the key unit operations in an integrated Lurgi SNG plant, including Lurgi gasification, tar and oil separation, Rectisol acid gas treatment and Phenosolvan process for phenol recovery. The sampling and analysis program, which addresses all major feed to and process streams from these and other units, consists of two phases: a "screening phase" (Phase I) and an "in-depth" effort (Phase II). Phase I, which is now being completed, involves analysis for selected constituents/parameters (e.g., H_2S, total hydrocarbons, C_1-C_6 organics, flow rates, etc.). Phase II involves a more comprehensive analysis for a range of constituents including identification/quantification of heavier organics using gas chromatograph/mass spectrometry (GC/MS) techniques and trace element analysis using spark source mass spectrometry (SSMS) and atmoic absorption (AA).

TABLE 6-4. SUMMARY OF THE MOST PERTINENT EPA-SPONSORED ON-GOING ENVIRONMENTAL ASSESSMENT PROGRAMS

Project Title	Contractor	Objective	Data Acquisition Activities
Environmental Assessment of High Btu Gasification	TRW, Inc. Redondo Beach, Ca.	Environmental assessment of high Btu gasification, including identification of control technology needs.	As part of this program, it is planned to conduct multimedia S/A at a foreign Lurgi plant.
Environmental Assessment of Low/Medium Btu Gasification	Radian Corporation Austin, Texas	Environmental assessment of low/medium Btu gasification, its utilization and definition of control technology needs.	Multimedia S/A under way at the Kosovo Kombiant plant in Pristina, Yugoslavia; Phase I, "screening," has been completed; Phase II, in-depth evaluation which would involve analysis for trace elements and heavy organics, is to be initiated in mid-1979.
Pollutants Identification from a Bench-Scale Unit	Research Triangle Institute Research Triangle Park North Carolina	Semi-quantitative determination of chemical species in gasification effluents as a function of gasification conditions and kinetic data on rates of species formation.	Lab-scale gasification reactor designed and operated with coke and Illinois #6 coal. It is planned to simulate conditions of a number of gasification systems, including Lurgi. S/A of gasifier feed and effluents are to be conducted.
Characterization of Coal and Coal Residues	Illinois State Geological Survey Urbana, Illinois	Characterization of the chemical, physical and mineral properties of coals, coal by-products and wastes; investigation of the effects of pyrolysis on trace element distribution and providing data on solubilities and toxicities of species in coal wastes.	Final report being prepared on studies of chemical form of trace elements in coal. Trace element studies conducted on ash from gasification of American coals at Westfield Lurgi facility. Toxicity and bioassay studies of coal and solid wastes recently completed.
Water Treating Bench-Scale Unit	University of No. Carolina Chapel Hill, No. Carolina	Assessment of the effectiveness of various biological/chemical processes for the treatment of synthetic fuel effluents, and determination of the environmental impacts and health effects of treated effluents.	Bench-scale studies being conducted in order to establish criteria for design of large-scale biological/chemical treatment units. Activated sludge, coagulation, and carbon adsorption processes have been tested on simulated gasification wastewaters. Bioassay testing of simulated wastewaters currently underway.
Gasification/Acid Gas Cleaning Bench-Scale Unit	No. Carolina State Univ. Raleigh, No. Carolina	Program is in initial stages. Evaluation of absorption solvents used in four acid gas removal processes (i.e., Rectisol, Benfield, MEA and Selexol) to be conducted.	Gasifier operation has been initiated with chemical grade coke. Rectisol solvent (i.e., methanol) tested with synthetic feed mixture and equilibrium solubilities of acid gases in MeOH determined. Future tests with lignite and subbituminous coal scheduled for May 1979.

TABLE 6-5. SUMMARY OF THE MOST PERTINENT DOE-SPONSORED ON-GOING ENVIRONMENTAL ASSESSMENT PROGRAMS

Contractor	Objective	Data Acquisition Activities
Carnegie-Mellon University Pittsburgh, Pa.	To provide overall coordination and evaluation for DOE pilot plant environmental assessment program; to develop sampling and analysis protocols.	Ten specific program tasks, including development/validation of sampling and analytical procedures, and studies on treatability of process effluents, are under way.
Oak Ridge National Laboratory Oak Ridge, Tennessee	To determine and assess potential environmental/health problems associated with coal conversion; to evaluate existing and developing environmental control processes applicable to coal conversion.	Program to characterize ash from gasification of Montana Rosebud and Illinois #5 and #6 coal from Westfield facility nearly completed. "Ecological bioassay" tests on Lurgi ash also being completed.
DOE-Environmental Division and American Society for Testing Materials Philadelphia, Pa.	To evaluate the validity of EPA's acid extraction test procedure proposed under RCRA as a method to classify wastes as hazardous or non-hazardous.	The 3-month study (January - March 1979) was recently initiated; up to 18 different samples of fly ash, scrubber sludge, gasification wastes and other residues are to be used in the assessment.

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APPENDICES

APPENDIX A. GLOSSARY OF ENVIRONMENTAL ASSESSMENT TERMS

Auxiliary Process. Process, associated with a technology, used for a purpose(s) that is in some way incidental to the main function involved in transformation of raw materials into end products. Auxiliary processes are used for recovery of by-products from waste streams (e.g., Phenosolvan process for phenol recovery), to furnish necessary utilities, and to furnish feed materials such as oxygen.

Commercial-scale SNG Facility. A facility having a capacity to produce 7×10^6 Nm^3/d (250×10^6 scf/d) of substitute natural gas.

Effluent Stream. A confined aqueous process waste stream, discharged from a source, which is potentially polluting.

Emissions Stream. A confined gaseous process waste stream, discharged from a source, which is potentially polluting.

Energy Technology. Consists of systems which are applicable to the production or processing of fuel (e.g., high Btu gasification), electricity, or chemical feedstocks from fossil fuels, radioactive materials, or natural energy sources (geothermal or solar).

Environmental Assessment. As defined for IERL/RTP studies of fossil energy processes, an environmental assessment is a continuing iterative study aimed at: (a) determining comprehensive multimedia environmental loadings and environmental control costs, from the application of existing and best future definable sets of control/disposal options, to a particular set of sources, processes, or industries; and (b) comparing the nature of these loadings with existing standards, estimated multimedia environmental goals, and bioassay specifications as a basis for prioritization of problems/control needs and for judgment of environmental effectiveness.

Environmental Assessment Report. A report prepared for a specific technology, covering in depth all environmental assessment information relevant to existing or needed standards development plus a description of systems which can make up the technology, the present and proposed environmental requirements, and the best control disposal alternatives for all media.

Fugitive Emissions. Unconfined process-associated discharges, including accidential discharges, of potential air pollutants, which may escape from pump seals, vents, flanges, etc., or as emissions in abnormal amounts when accidents occur and may be associated with storage, processing, or transport of materials as well as unit operations associated with a process.

Hazard Indicators. An EPA-developed ranking system which assigns one of four indicators to substances: N = non-hazardous, x = hazardous, xx = very hazardous, xxx = most hazardous. The indicators have been derived from numerical ratings of substances which are based on human health effects and include weightings for substances indicated to be cumulative or to be hazardous at low concentrations.

High Btu Gas. Gas having a higher heating value of over 8000 Kcal/Nm^3 (900 Btu/scf).

LD_{50}. Lethal dose fifty, i.e., the dose which when administered to a group of animals is lethal to one-half of the population. The mode of administering the dose and the test animal must be specified.

LD_{Lo}. Lethal does low, i.e., the lowest dose of a substance introduced in one or more portions by any route other than inhalation over any period of time and reported to have caused death in a particular animal species.

Low/Medium-Btu Gas. Gas having a higher heating value of 800-3600 Kcal/Nm^3 (90-400 Btu/scf).

Lurgi SNG Systems. Systems which incorporate specific Lurgi-licensed processes and various other processes which would be used in an integrated SNG facility.

Minimum Acute Toxicity Effluent (MATE). The approximate concentration for contaminants in source emissions which will not evoke significant harmful or irreversible responses in exposed humans or ecology, when those exposures are limited to short durations (less than 8 hours per day).

Multimedia. Pertaining to air, water and/or land as recipients of environmental pollutants; or gaseous, liquid or solid waste pollutants when used in relation to pollution control levels.

Multimedia Environmental Goals (MEG's). Levels of significant contaminants or degradents (in ambient air, water, or land or in emissions or effluents conveyed to the ambient media) that are judged to be (a) appropriate for preventing certain negative effects in the surrounding populations or ecosystems or (b) representative of the control limits achievable through technology.

Operation. A specific function associated with a technology consisting of a set of processes used to produce specific products from certain raw materials. For example, the operations for high-Btu gasification technology are coal pretreatment, coal gasification, gas purification and gas upgrading.

Phased Approach for Sampling/Analysis. A strategy for environmental assessment in which all streams to be sampled at a source are first surveyed using simplified, generalized S/A methods so they can be ranked on a priority basis (e.g., very hazardous versus less hazardous), followed by detailed sampling/analysis in order of descending priority. Requires three levels of S/A effort. Level 1 entails comprehensive screening for pollutants, including criteria pollutants; Level 2, directed analysis, based on Level 1; and Level 3, process monitoring of selected pollutants, based on Levels 1 and 2.

Process. A basic unit that comprises a technology, used to produce chemical or physical transformations of input materials into specific output streams, and having a unique definable set of waste streams (e.g., Lurgi gasification).

Process Module. A representation of a process which is used to display process input and output stream characteristics, and which, when used with other necessary process modules, can be used to describe a technology, a system or a plant. A module is comprised of a number of nearly interchangeable processes or processes applicable to different operating conditions and input requirements.

Process Stream. An output stream from a process that is an input stream to another process in the technology. For example, the raw gas liquor from the Lurgi gasification process is the feed (input) stream to the tar and oil separation process.

Source Assessment Models (SAM's). Models for systematic assessment of the environmental effectiveness of pollution control options. Four models are under development: SAM/IA for rapid screening, SAM/IB for biological screening, SAM/I for screening, and SAM/II for providing the general approach to evaluation of U.S. regional site alternatives.

Substitute Natural Gas (SNG). A manufactured gas containing about 97% methane, with a higher heating value of over 8000 Kcal/Nm^3 (900 Btu/scf), and meeting the same end-use specifications as pipeline natural gas.

System. A specified set of processes that can be used to produce a specific end-product of the technology, e.g., high-Btu gasification. The technology is comprised of several systems.

TL_m. Median tolerance limit value, i.e., the concentration in water of a pollutant required to kill 50 percent of a particular aquatic species during a specified period of exposure (usually 24, 48 or 96 hours).

TLV. Threshold limit value, i.e., levels of contaminants considered safe for workroom atmosphere, as established by the American Conference of Governmental Industrial Hygienists.

Potential Toxic Unit Discharge Rate (PTUDR). Number which expresses the effectiveness of pollution control options, equal to the ratio of the pollutant concentration to the MATE value (called the "potential degree of hazard," H) times the stream flow rate.

Waste Stream. Confined gaseous, liquid, and solid process output streams that are sent to auxiliary processes for recovering by-products, pollution control or final disposal; also, unconfined "fugitive" discharges of gaseous of aqueous waste and accidental process discharges.

APPENDIX B. SUPPORT DATA FOR ESTIMATION OF EMISSIONS, COSTS AND ENERGY REQUIREMENTS FOR AIR POLLUTION CONTROL OPTIONS FOR INTEGRATED SNG PLANTS

BASIS FOR ESTIMATING STREAM FLOWS AND EMISSIONS FOR VARIOUS OPTIONS

(See Figures B-1 through B-5 for flow diagrams and stream flows)

- A 7.7 x 10^6 Nm^3/d (288 x 10^6 scf/d) Lurgi SNG plant using 0.7% sulfur subbituminous coal.
- All plant energy requirements are met by use of coal, fuel gas, or gasification by-products onsite. Total plant energy requirements are the same for all options.
- In Options 1 and 5, incineration of Stretford off-gases using supplemental fuel will oxidize all sulfur compounds to SO_2 and will reduce CO and HC levels to 200 ppmv and 100 ppmv, respectively.
- Incineration of Stretford off-gases in turbines (Option 2) or in fossil fuel-fired boilers (all options) oxidizes all sulfur compounds to SO_2. The amounts of CO, HC and NO_x in turbine or boiler flue gases are estimated from emission factors in Reference 109, using combined heating values of fuels and Stretford off-gases.
- Flue gas desulfurization processes are capable of 90% SO_2 removal with the percent removal independent of feed SO_2 concentration. The Wellman-Lord process is assumed to be used for FGD in Options 1, 3, 4 and 5.
- Electrostatic precipitators are used for particulate control and remove 99% of flue gas particulates, with an additional 80% removal occuring in FGD units. (An overall 99.8% particulate control is realized.)
- NO_x emissions from boilers, turbines and superheaters are estimated using the data in Reference 109 and are assumed to be unaffected by dilution of fuel/flue gases with waste gases to be incinerated. (Such dilution might be expected to reduce NO_x emissions somewhat.)
- Boilers are fired with 20% excess air. Gas turbines are generally operated at about 400% excess air. Stretford off-gases displace about 30% of this excess turbine air in Option 2.
- Although the Rectisol process generates at least two acid gas streams (commonly referred to as lean H_2S and rich H_2S streams), acid gases are

combined into one stream in Options 1, 2, 3 and 4. In Option 5 the Rectisol design generates a rich H_2S stream containing about a third of the total sulfur and a lean H_2S stream containing the other two thirds. The composition and flow rate for the Rectisol acid gases are those used in the proposed design for the El Paso facility (as described in References 12 and 31).

- COS and CS_2 in raw product gas feed to Rectisol unit constitute 2% of the total gaseous sulfur and are entirely removed by the Rectisol process. In Option 5, COS and CS_2 are in the lean and rich H_2S streams in equal amounts. Mercaptans and thiophenes which may amount to another 2% of the total gaseous sulfur are removed with the naphtha fraction in the Rectisol process and thus are accounted for in the naphtha sulfur content.
- The Stretford process reduces the H_2S in Rectisol off-gases to less than 10 ppmv. The Stretford unit which treats the fuel gas in Option 2 achieves an H_2S level of 100 ppmv. COS and organic compounds are not removed by the Stretford process.
- The ADIP process in Option 3 is capable of producing a Claus plant feed containing a minimum of 15% H_2S and an off-gas containing 250 ppmv H_2S when handling Rectisol off-gases. Hydrocarbons and COS contained in Rectisol acid gases will be in the dilute H_2S stream.
- When operated in the split-flow mode and treating a 15% H_2S feed, the Claus process can remove 94% of the total sulfur. A tail gas containing about 12,000 ppmv total sulfur is generated with the following approximate composition (based on the data in Reference 129):

  SO_2 = 3500 ppmv
  H_2S = 7000 ppmv
  COS + CS_2 = 1400 ppmv
  S_x = 100 ppmv
- The Beavon/Stretford process for Claus tail gas treatment is capable of producing a tail gas containing 250 ppmv total sulfur. The predominant sulfur species is COS. Beavon tail gas contains about 1000 ppmv HC and 2000 ppmv CO.

BASIS FOR ESTIMATING ENERGY REQUIREMENTS FOR VARIOUS OPTIONS

- Direct steam, electricity, and fuel requirements for air pollution control processes are as listed in Table B-1. These utility estimates are for units of a size similar to that which would be encountered in a Lurgi SNG facility and assume input stream compositions representative of those in Lurgi plants.
- Electricity is generated at 34% efficiency, steam at 80% efficiency.
- Fuel for Beavon process and for reductive incineration of Stretford purge is SNG made from coal at 65% thermal efficiency.
- The amount of energy which can be recovered in incineration of waste gases using supplemental fuel is directly proportional to the combustion (flame) temperature.
- No heat is recovered from waste gases having temperatures less than 420°K (300°F).
- An incineration temperature of 1140°K (1600°F) is required for destruction of HC and CO.* The incineration energy penalties for each option are calculated in Table B-2.
- The use of gas turbines in Option 2 for incineration does not involve a thermal penalty since the gas to be incinerated is displacing excess air and should not affect turbine combustion temperatures. The heating value of Stretford off-gas is not recovered in the turbines. The overall thermal efficiency of gas turbine/steam turbine systems is the same as for steam turbines alone so that no energy penalty is associated with combustion of the waste gases.

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*Certain incinerator designs can achieve effective destruction of certain simple gaseous wastes at temperatures below 1090°K (1500°F). In a pilot plant study of incineration of a butane-pentane mixture in air using a low-NO_x burner, residual CO, HC and NO_x levels of less than 35, 45 and 10 ppm, respectively, were obtained at temperatures below 1090°K (1500°F) - see EPA 650/2-75-042. To assure complete combustion in the incineration of complex wastes, temperatures of 1150°K (1600°F) or more are commonly specified.

TABLE B-1. SUMMARY OF ENERGY REQUIREMENTS FOR AIR POLLUTION CONTROL PROCESSES

Process	Reference	Steam	Electricity	Fuel
Stretford	1,22	830 kg/tonne S @0.4 MPa (50 psig)	1353 kwh/tonne S	2.5 x 10^6 kcal/tonne* S
Claus	22	437 kg/tonne S @ 4 MPa (600 psig) consumed 4910 kg/tonne S @0.4 MPa (60 psig) produced	36 kwh/tonne S	--
ADIP	22	4600 kg/tonne S @0.4 MPa (30 psig)	13 kwh/tonne S	--
Beavon	129	705 kg/tonne S @0.4 MPa (50 psig)	312 kwh/tonne S	1.2 x 10^6 kcal/tonne S
Wellman-Lord	22	18,700 kg/tonne S @0.1 MPa (15 psig)	1120 kwh/tonne S	--
Electrostatic Precipitator	59	--	70-123 kw/actual cubic meter per minute	--

*Reductive incineration of Stretford purge solution for vanadium/sodium recovery.

TABLE B-2. ESTIMATED ENERGY PENALTY ASSOCIATED WITH INCINERATION IN AIR POLLUTION CONTROL OPTIONS

Option	Quantity of Gas to be Incinerated 10^6 Nm^3/hr (10^6 scf/hr)	Quantity of Fuel Used for Incineration	Theoretical Adiabatic Flame Temperature* (°K)	Theoretical Efficiency of Heat Recovery (%)	Energy Penalty† 10^9 cal/hr	(% of theoretical)
1	0.36 (13.3)	3.37×10^3 kg/hr (74.2×10^3 lb/hr)	1600	73.8	28.00	(8.8)
2	0.36 (13.3)	0.235×10^6 Nm^3/hr (8.76×10^6 scf/hr)	--	--	0	(0)
3	0.34 (12.66)	1.27×10^6 kg/hr (280×10^3 lb/hr)	2040	79.4	22.37	(1.9)
4	0.34 (13.4)	1.27×10^6 kg/hr (280×10^3 lb/hr)	2022	79.2	25.19	(2.1)
5	0.34 (12.7)	33,000 kg/hr (72,700 lb/hr)	1600	73.8	27.39	(8.8)

*See calculations which follow this table.

†Energy penalty is the difference between theoretical efficiencies associated with combustion of fuel alone (82.5%) and combustion of fuel diluted with Stretford or ADIP off-gases.

- The basic energy efficiency for the production of the fuel gas from coal is 80%. Since in Option 2 the fuel gas is not treated in an FGD or particulate removal system, an energy credit is taken for such a system which is not utilized. This credit is estimated from that in Option 5.

CALCULATION OF FLAME TEMPERATURES ASSOCIATED WITH INCINERATION OF WASTE GASES

Methane or Fuel Gas as Fuel

Combustion of methane in air can be represented as follows:

$$CH_4 + 2O_2 + 8N_2 = CO_2 + 2H_2O + 8N_2 \quad \Delta H = 192 \text{ kcal/gram mole (LHV)} \qquad (1)$$

Adiabatic combustion results in the absorption of all the reaction heat by the combustion products; the final temperature, T_C, is the flame temperature:

$$- \Delta H = n\overline{C}p \, (T_c - T_o)$$

where n is the number of moles of combustion products, Cp is the average heat capacity of the products, and T_o is the initial temperature (assumed to be 298°K). It is helpful to express Cp as a multiple of the gas constant R and ΔH as a multiple of the thermal energy unit RT_o:

$$\overline{C}p = aR \qquad (2)$$

$$- \Delta H = hRT_o \qquad (3)$$

The dimensionless specific heat, "a" is estimated at about 4.5, $RT^\circ = 0.592$ kcal/mole. Solving for flame temperature:

$$T_c = T_o \, (1 + h/na) \qquad (4)$$

where $h = 324$, $n = 11$, and $a = 4.5$

$$T_c = 298 \, (7.55) = 2250°K \text{ (for pure methane)}$$

To calculate the flame temperature of fuel gas it is assumed that the combustible components can be represented by methane and that heating value of the gas is directly proportional to methane content. Thus, a fuel gas with one half the heating value of methane would have a flame temperature calculable from equation (4) using $n = 12$ rather than $n = 11$ (i.e., CH_4 in equation (1) would be diluted by one mole of inert gas, say N_2). Thus, for a gas with one half the heating value of methane:

$$T_c = 298 \left(1 + \frac{324}{(12)(4.5)}\right) = 2086°K$$

If a diluent gas (D) is added to the methane and the diluent also contains heating value, the following is used to estimate the flame temperature:

$$\frac{V_{CH_4} \cdot \Delta H_{CH_4} + V_D \cdot \Delta H_D}{V_{CH_4} + V_D} = \overline{\Delta H} \text{ of gas} \tag{5}$$

A methane gas equivalent in heating value to the diluted gas having a heating value equal to $\overline{\Delta H}$ would have a total number of moles of combustion products defined by:

$$\frac{\Delta H_{CH_4} - \overline{\Delta H}}{\overline{\Delta H}} + 11 = n \tag{6}$$

Thus, a fuel gas with one-tenth the heating value of methane would have an n = 20, or:

$$\frac{1 - 0.1}{0.1} + 11 = 20$$

Its flame temperature would be:

$$T_c = 298 \left(1 + \frac{324}{(20)(4.5)}\right) = 1371°K$$

Coal or Tars and Oils as Fuel

Combustion of coal, tars, or oils having a C/H ratio of about 1/1 can be represented as:

$$CH + 1.25O_2 + 5N_2 = CO_2 + 0.5H_2O + 5N_2$$

Assuming that such fuels have a net heating value approximated by benzene (C_6H_6) on an MAF basis then ΔH = 123 kcal/mole CH. As in the case of methane combustion above, the adiabatic flame temperature can be calculated according to equation (4) with h = 207, a = 4.5 and n = 6.5, or:

$$T_c = 298 \quad 1 + \frac{207}{(6.5)(4.5)} = 2406°K$$

As in the case of methane, adding an inert or waste gas to combustion products results in an increase in the number of moles of products which must be heated, thus lowering the flame temperature. The flame temperature of a gas incinerated with fuels represented by CH is calculated as follows. The CH fuel is assumed to have a molecular weight of 13 and if it were a gas would occupy 22.4 l/mole at STP. The weight of fuel used for incinerating a waste gas is converted to its equivalent volume of CH gas and its heating value is assumed to be 123 kcal/gram mole (or 4958 kcal/Nm^3). Using the heating value and volume of the waste gas (W):

$$\frac{V_{CH} \times \Delta H_{CH} + V_W \times \Delta H_W}{V_{CH} + V_W} = \overline{\Delta H} \tag{8}$$

and n is then calculated by:

$$\frac{\Delta H_{CH} - \overline{\Delta H}}{\overline{\Delta H}} + 6.5 = n \tag{9}$$

The flame temperature is calculated according to equations (3) and (4). For example, a waste gas with a heating value of 410 kcal/Nm^3 (50 Btu/scf) is incinerated with coal at a ratio of 1.2 kg coal/Nm^3 (1 lb coal/15 scf) waste gas.

$$\frac{1200 \text{ grams coal} \times 22.4}{13 \times 1000} = 2.068 \text{ Nm}^3 \text{ CH}$$

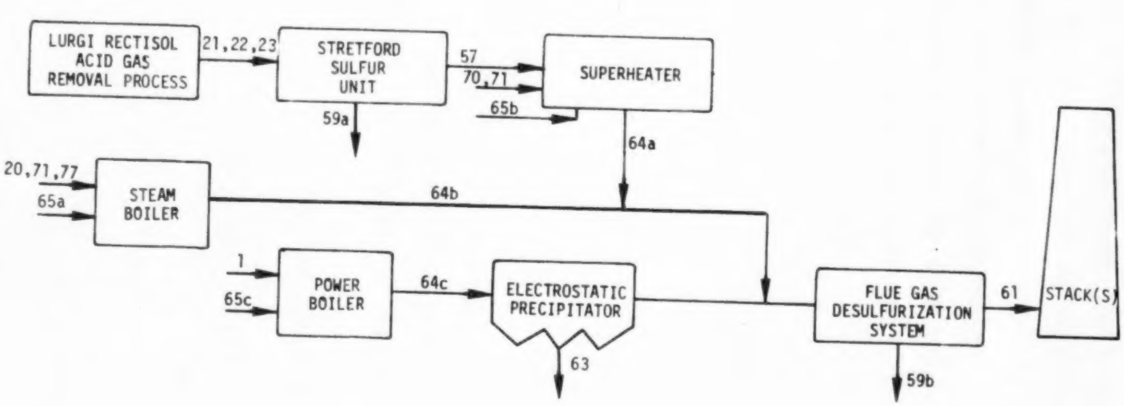
$$\frac{2.068 \times 4958 + 1 \times 410}{3.068} = \frac{3477 \text{ kcal}}{\text{Nm}^3} \text{ or } \frac{86 \text{ kcal}}{\text{mole}}$$

From equation (9)

$$\frac{4958 - 3477}{3477} + 6.5 = n = 6.93$$

Then from equation (4)

$$T_c = 298 \left(1 + \frac{207}{(6.93)(0.45)}\right) = 2276°K$$


LURGI RECTISOL ACID GAS REMOVAL PROCESS
21,22,23
STRETFORD SULFUR UNIT
59a
57
70,71
65b
SUPERHEATER
64a
20,71,77
65a
STEAM BOILER
64b
1
65c
POWER BOILER
64c
ELECTROSTATIC PRECIPITATOR
63
FLUE GAS DESULFURIZATION SYSTEM
59b
61
STACK(S)

STREAM FLOWS FOR OPTION 1*

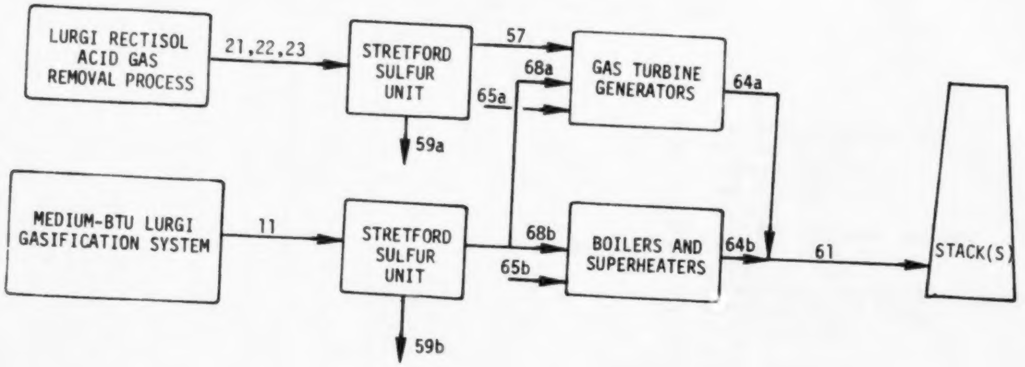
Component	Stream Flows in 10^3 kg/hr														
	21,22,23	57	70,71	65a	20,71,77	65b	1	65c	64a	64b	64c	63	59a	61	59b
C			28		14.4		31.2								
H			2.6		1.4		2.3								
S			0.23		.045		.45						0.77		5.8
O			2.6	154	1.9	57	6.5	114	25	9.4	19			54	
N	.045	.045	0.23	481	.045	214	1.2	430	581	214	430			1266	
Ash			0.45			2.7	9.7		.045		9.7	9.7		0.06	
H_2O				7.4			7.9	5.4	5.0	15	34			363	
CO_2	719	719							851	528	114			1018	
H_2S	6.2	.01													
$COS+CS_2$	0.22	0.22													
C_2H_4	1.4	1.4													
CO	2.9	2.9							.21	.01	.02			0.24	
H_2	0.2	0.2													
CH_4	4.6	4.6													
C_2H_6	2.0	2.0													
MeOH	1.2	1.2													
NO_x									0.6	0.27	0.36			1.2	
HC									0.06	.005	.005			0.07	
SO_2									0.72	0.09	0.90			0.17	

*Stream numbers refer to Figures 2-2, 2-3 and 2-4. See Table 2-7 for stream index.

LEGEND:

21,22,23	COMBINED GASES FROM RECTISOL UNIT
57	OFF-GAS FROM STRETFORD
70,71	TAR AND TAR OIL
65a	COMBUSTION AIR
71,20,77	TAR OIL, NAPHTHA AND PHENOLS
65b	COMBUSTION AIR
1	COAL
65c	COMBUSTION AIR
64a	SUPER-HEATING FLUE GAS
64b	STEAM BOILER FLUE GAS
64c	POWER BOILER FLUE GAS
63	BOILER & FLY ASH
59a	SULFUR
61	COMBINED FLUE GAS TO STACK
59b	ELEMENTAL SULFUR

Figure B-1. Air Pollution Control Option 1


LURGI RECTISOL ACID GAS REMOVAL PROCESS
21,22,23
STRETFORD SULFUR UNIT
59a
57
68a
65a
GAS TURBINE GENERATORS
64a
MEDIUM-BTU LURGI GASIFICATION SYSTEM
11
STRETFORD SULFUR UNIT
59b
68b
65b
BOILERS AND SUPERHEATERS
64b
61
STACK(S)

STREAM FLOWS FOR OPTION 2*

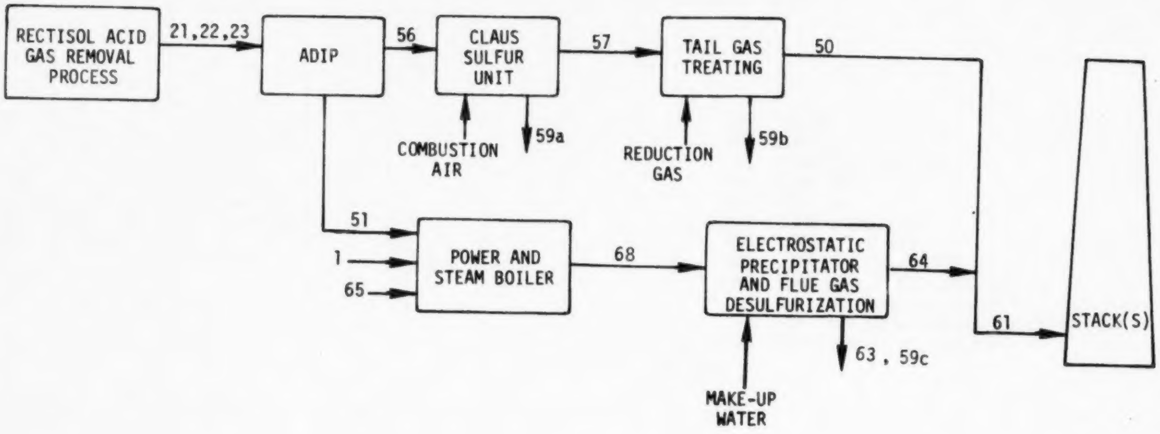
Component	Stream Flow in kg/hr											
	21,22,23	11	57	68a	68b	65a	65b	64a	64b	61	59a	59b
C												
H												
S											6.0	1.2
O						214	28	25	5.0	30		
N	.045	182	.045	159	24	805	104	964	127	1091		
Ash												
H_2O		0.8		0.7	0.1	10.2	1.3	123	16	138		
CO_2	719	110	719	96	14			937	37	1034		
H_2S	6.2	1.3	.01	.002	.0003							
$COS+CS_2$	0.22	.023	0.22	.020	.003							
C_2H_4	1.4	1.2	1.4	1.0	0.1							
CO	2.9	83	2.9	72	10.7			0.1	.005	.10		
H_2	0.2	7.9	0.2	7.9	1.0							
CH_4	4.6	1.4	4.6	14	1.8							
C_2H_6	2.0	1.9	2.9	1.9	0.3							
MeOH	1.2	--	1.2	--	--							
NO_x								0.40	1.1	1.5		
HC								.045	.002	.047		
SO_2								0.26	.007	.27		

*Stream numbers refer to Figures 2-2, 2-3 and 2-4. See Table 2-7 for stream index.

LEGEND:

21,22,23	GASES FROM RECTISOL UNIT
11	FUEL GAS FROM LOW-BTU GASIFICATION
57	OFF-GAS FROM STRETFORD
68a	FUEL GAS TO GAS TURBINES
68b	FUEL GAS TO BOILERS
65a	COMBUSTION AIR
65b	COMBUSTION AIR
64a	FLUE GAS
64b	FLUE GAS
61	COMBINED FLUE GAS
59a	SULFUR
59b	SULFUR

Figure B-2. Air Pollution Control Option 2


RECTISOL ACID GAS REMOVAL PROCESS
21,22,23
ADIP
56
CLAUS SULFUR UNIT
COMBUSTION AIR
59a
57
TAIL GAS TREATING
REDUCTION GAS
59b
50
51
1
65
POWER AND STEAM BOILER
68
ELECTROSTATIC PRECIPITATOR AND FLUE GAS DESULFURIZATION
MAKE-UP WATER
63 , 59c
64
61
STACK(S)

STREAM FLOWS FOR OPTION 3*

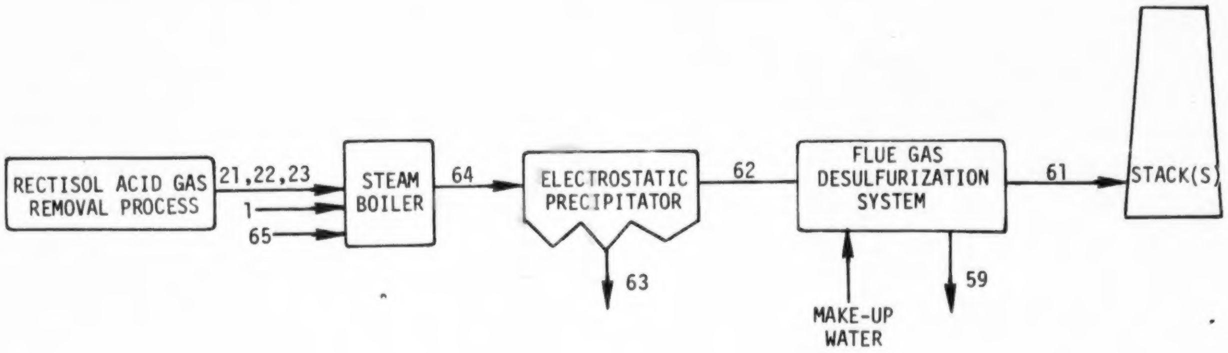
Component	Stream Flow in 10^3 kg/hr												
	21,22,23	1	65	56	51	57	59a	50	59b	68	64	63,59c	61
C		97											
H		7.1											
S		1.4					5.4		0.4			1.2	
O		20	400							65	65		65
N	.045	1.7	1500			9.3		9.3		1510	1510		1510
Ash		30								30	.05	29.5	.05
H_2O		24	19			2.6				126	417		417
CO_2	719			42	677	42		42		1070			
H_2S	6.2			6.0	0.20	0.24		.001					
$COS+CS_2$	0.22				0.22	0.08		.010					.018
C_2H_4	1.4				1.4								
CO	2.9				2.9			0.05		.05	.05		0.10
H_2	0.2				0.2								
CH_4	4.6				4.6								
C_2H_6	2.0				2.0								
MeOH	1.2				1.2								
NO_x										1.1	1.1		1.1
HC								0.02		.02	.02		0.04
SO_2						0.24				2.8	0.28		0.28

*Stream numbers refer to Figures 2-2, 2-3 and 2-4. See Table 2-7 for stream index.

LEGEND:

21,22,23	GASES FROM RECTISOL UNIT
1	COAL
65	COMBUSTION AIR
56	CONCENTRATED H_2S STREAM
51	HYDROCARBON CONTAINING STREAM TO BOILER
57	CLAUS TAIL GAS
59a	SULFUR
50	TAIL GAS TREATMENT OFF-GAS
59b	SULFUR
64	RAW FLUE GAS
68	TREATED FLUE GAS
63,59c	ASH AND SULFUR
61	COMBINED GASES TO STACK

Fibure B-3. Air Pollution Control Option 3


RECTISOL ACID GAS REMOVAL PROCESS
21,22,23
1
65
STEAM BOILER
64
ELECTROSTATIC PRECIPITATOR
63
62
FLUE GAS DESULFURIZATION SYSTEM
MAKE-UP WATER
59
61
STACK(S)

STREAM FLOWS FOR OPTION 4*

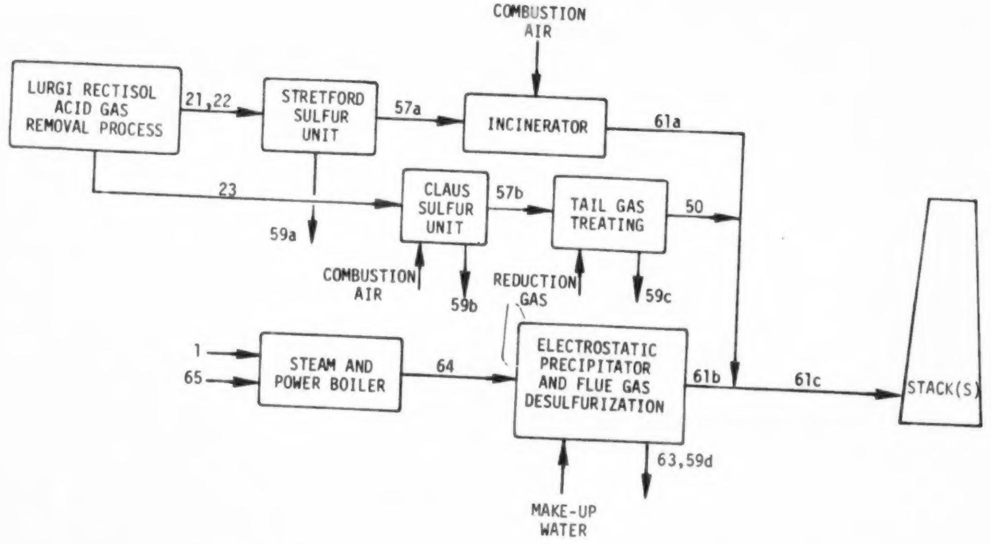
	Stream Flow in 10^3 kg/hr							
Component	21,22,23	65	1	64	63	62	59	61
C			97					
H			7.1					
S			1.4				69	
O		409	20	61.3		61.6		61.6
N_2	.045	1539	1.7	1540		1540		1540
Ash			30.2	30.2	29.9	0.30	0.27	.05
H_2O		20	24	139		139		425
CO_2	719			1100		1100		1100
H_2S	6.2							
$COS+CS_2$	0.22							
C_2H_4	1.4							
CO	2.9			.05		.05		.05
H_2	0.2							
CH_4	4.6							
C_2H_6	2.0							
MeOH	1.2							
NO_x				1.1		1.1		1.1
HC				0.02		0.02		0.02
SO_2				14.7		14.7		1.5

*Stream numbers refer to Figures 2-2, 2-3 and 2-4. See Table 2-7 for stream index.

LEGEND:

1	COAL
65	COMBUSTION AIR
21,22,23	ACID GASES FROM RECTISOL UNIT
64	RAW FLUE GAS
63	ASH
62	ASH FREE FLUE GAS
59	SULFUR
61	TREATED FLUE GAS

Figure B-4. Air Pollution Control Option 4


COMBUSTION AIR
LURGI RECTISOL ACID GAS REMOVAL PROCESS
21,22
STRETFORD SULFUR UNIT
57a
INCINERATOR
61a
23
59a
CLAUS SULFUR UNIT
57b
TAIL GAS TREATING
50
COMBUSTION AIR
59b
REDUCTION GAS
59c
1
65
STEAM AND POWER BOILER
64
ELECTROSTATIC PRECIPITATOR AND FLUE GAS DESULFURIZATION
61b
61c
STACK(S)
63,59d
MAKE-UP WATER

STREAM FLOWS FOR OPTION 5*

Component	Stream Flows in 10^3 kg/hr														
	21,22	23	1	65	57a	59a	57b	59b	50	59c	64	61a	63,59d	61b	61c
C			97												
H			7.1												
S			1.4			4.3		1.8		.07			1.2		
O			20								59			3.4	62
N			1.7	356			4.3		4.3		1341			76	1421
Ash			30.2	1340							30.2	0.05	30.1		.05
H_2O			24	17			1.2		1.2		105			9.5	287
CO_2	695	15.3			695		15.3		15.3		356			709	1080
H_2S	4.3	1.9			.005		.064		.0003						
$COS+CS_2$	0.11	0.11			0.11		.020		.005						.005
C_2H_4	1.1				1.1										
CO	0.77				0.77				.03		.05	.05		.05	.13
H_2	0.14				0.14										
CH_4	1.4	0.1			1.4										
C_2H_6	1.5				1.5				.01						
MeOH		1.2													
NO_x											1.1	1.1		0.1	1.2
HC											.02	.02		0.02	0.13
SO_2							.064				2.8	0.28		0.23	0.515

*Stream numbers refer to Figures 2-2, 2-3 and 2-4. See Table 2-7 for stream index.

LEGEND:

21,22	LEAN H_2S RECTISOL OFF-GAS
23	RICH H_2S RECTISOL OFF-GAS
1	COAL
65	COMBUSTION AIR
57a	STRETFORD OFF-GAS
59a	SULFUR
57b	CLAUS TAIL GAS
59b	SULFUR
50	TAIL GAS TREATMENT OFF-GAS
59c	SULFUR
64	RAW FLUE GAS
61a	TREATED FLUE GAS
63,59d	ASH AND SULFUR
61b	INCINERATED STRETFORD OFF-GAS
61c	COMBINED FLUE GAS

Figure B-5. Air Pollution Control Option 5

APPENDIX C. MATERIAL RELATED TO EPA METHODOLOGY FOR ENVIRONMENTAL ASSESSMENT

TABLE C-1. SUMMARY OF ENVIRONMENTAL ASSESSMENT
METHODOLOGIES UNDER DEVELOPMENT BY EPA

Methodology	Description
Environmental Data Acquisition (100,102)	To study the pollutant sources in a plant, such sources are identified and organized by unit operations (Example: wind-blown dusts, water runoff and leakage/venting as pollutant sources for material storage). A phased approach consisting of 3 levels of progressively more directed and detailed effort has been developed for process/waste stream sampling and analysis. The three levels are: "Level 1", comprehensive screening (including for "criteria" pollutants); "Level 2", directed detailed analysis, based on Level 1; and "Level 3", process monitoring of selected priority pollutants, based on Levels 1 and 2.
Current Environmental background (97,101,103)	Compilation and continuous upgrading of data on (a) physical, chemical and toxicological properties of specific pollutants, (b) pollutants transport/transformation models, and (c) trace substances in the ambient environment.
Environmental Objectives Development (98) (Multimedia Environmental Goals, MEG's)	The "MEG methodology" is a systematic means for the prioritization of the chemical substances in complex effluents for the purpose of environmental assessment. MEG's are levels of significant contaminants or degradants that are judged to be (1) appropriate for preventing certain negative effects in the surrounding populations or ecosystems, or (2) representive of the control limits achievable through technology. To date MEG's have been established for 210 substances. MEG's are generally derived through models which translate toxicological data, recommended concentration levels and federal standards or criteria into emissions or ambient level goals.
Control Technology Assessment (97)	A "Multimedia Environmental Control Manual" which provides a stepwise guidance for defining specific control options for specific situations is under development. Pollution Control Guidance Documents which provide integrated, multimedia, industry oriented, single-package review of the environmental requirements, guidelines and best control/disposal options and accounts for variations needed for different regional site alternatives are being developed for a number of basic energy processes at the commercial or demonstration stage (e.g., low Btu gasification). Work on Control Assay Development (CAD) for coal conversion processes is in progress. CAD's objective is to perform quick screening treatments on streams suspected of containing pollutants requiring control.

(continued)

TABLE C-1. CONTINUED

Methodology	Description
Environmental Alternatives Analysis(100) (Source Assessment Models - SAM's)	SAM's are environmental assessment tools helpful in the following areas: (a) rank individual effluent streams by their toxicity, (b) establish sampling priorities, (c) determine problem pollutants, (d) recommend best multimedia control technology alternatives, and (e) recommend control technology development programs. Four models under development are SAM/IA for rapid screening, SAM/IB for biological screening, SAM/I for screening and SAM/II for providing the general approach to evaluating any U.S. regional site alternatives. The simplest of the models, SAM/IA, which is fully developed, is based on a comparison of effluent concentration with the set of Minimum Acute Toxicity Effluent (MATE) criteria established by EPA.
Environmental Assessment Reports (EAR)	EAR provides the EPA Administrator, Program Offices and Policy and Planning with a recognized, authoritative document representing OR&D's environmental assessment research input on standards (supporting data, needs, alternatives) for a given technology. The report provides a comprehensive, multimedia, multipollutant data base and checklist of environmental facts concerning the technology covered. Recognizing the evolutionary state of the technologies and of environmental assessment methodology, the report will be expanded, refined, and updated every one or two years as needed for Agency purposes. This report is the EAR for Lurgi coal gasification systems for SNG production; EAR's for Wellman Galusha coal gasification systems for low/medium Btu gas production and for SRC coal liquefaction technology are also being prepared.

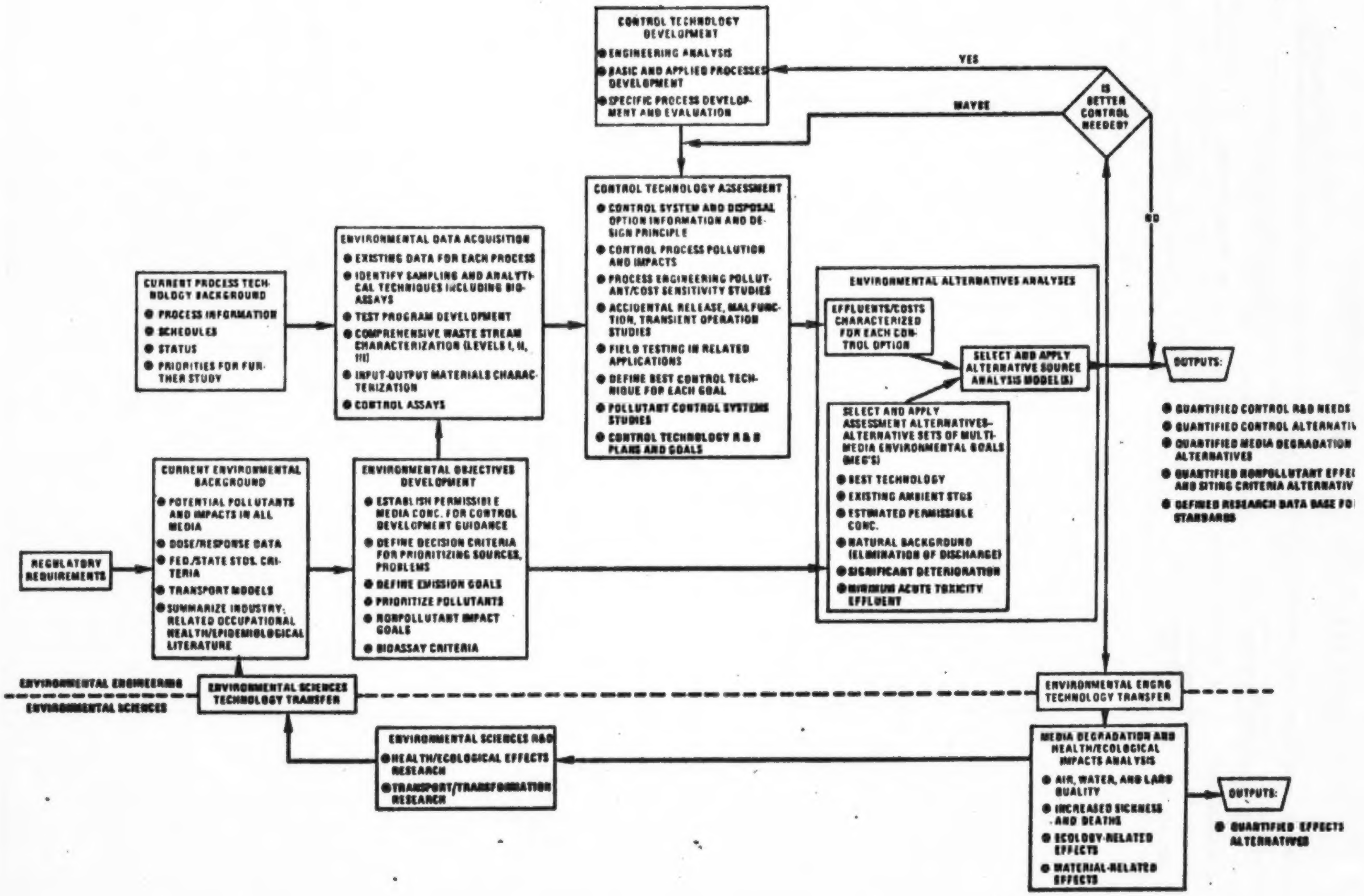

CONTROL TECHNOLOGY DEVELOPMENT
● ENGINEERING ANALYSIS
● BASIC AND APPLIED PROCESSES DEVELOPMENT
● SPECIFIC PROCESS DEVELOPMENT AND EVALUATION
YES
MAYBE
IS BETTER CONTROL NEEDED?
NO
CURRENT PROCESS TECHNOLOGY BACKGROUND
● PROCESS INFORMATION
● SCHEDULES
● STATUS
● PRIORITIES FOR FURTHER STUDY
ENVIRONMENTAL DATA ACQUISITION
● EXISTING DATA FOR EACH PROCESS
● IDENTIFY SAMPLING AND ANALYTICAL TECHNIQUES INCLUDING BIOASSAYS
● TEST PROGRAM DEVELOPMENT
● COMPREHENSIVE WASTE STREAM CHARACTERIZATION (LEVELS I, II, III)
● INPUT-OUTPUT MATERIALS CHARACTERIZATION
● CONTROL ASSAYS
CONTROL TECHNOLOGY ASSESSMENT
● CONTROL SYSTEM AND DISPOSAL OPTION INFORMATION AND DESIGN PRINCIPLE
● CONTROL PROCESS POLLUTION AND IMPACTS
● PROCESS ENGINEERING POLLUTANT/COST SENSITIVITY STUDIES
● ACCIDENTAL RELEASE, MALFUNCTION, TRANSIENT OPERATION STUDIES
● FIELD TESTING IN RELATED APPLICATIONS
● DEFINE BEST CONTROL TECHNIQUE FOR EACH GOAL
● POLLUTANT CONTROL SYSTEMS STUDIES
● CONTROL TECHNOLOGY R & D PLANS AND GOALS
ENVIRONMENTAL ALTERNATIVES ANALYSES
EFFLUENTS/COSTS CHARACTERIZED FOR EACH CONTROL OPTION
SELECT AND APPLY ALTERNATIVE SOURCE ANALYSIS MODEL(S)
SELECT AND APPLY ASSESSMENT ALTERNATIVES–ALTERNATIVE SETS OF MULTIMEDIA ENVIRONMENTAL GOALS (MEG'S)
● BEST TECHNOLOGY
● EXISTING AMBIENT STDS
● ESTIMATED PERMISSIBLE CONC.
● NATURAL BACKGROUND (ELIMINATION OF DISCHARGE)
● SIGNIFICANT DETERIORATION
● MINIMUM ACUTE TOXICITY EFFLUENT
OUTPUTS:
● QUANTIFIED CONTROL R&D NEEDS
● QUANTIFIED CONTROL ALTERNATI
● QUANTIFIED MEDIA DEGRADATION ALTERNATIVES
● QUANTIFIED NONPOLLUTANT EFFE AND SITING CRITERIA ALTERNATIV
● DEFINED RESEARCH DATA BASE FO STANDARDS
REGULATORY REQUIREMENTS
CURRENT ENVIRONMENTAL BACKGROUND
● POTENTIAL POLLUTANTS AND IMPACTS IN ALL MEDIA
● DOSE/RESPONSE DATA
● FED./STATE STDS. CRITERIA
● TRANSPORT MODELS
● SUMMARIZE INDUSTRY; RELATED OCCUPATIONAL HEALTH/EPIDEMIOLOGICAL LITERATURE
ENVIRONMENTAL OBJECTIVES DEVELOPMENT
● ESTABLISH PERMISSIBLE MEDIA CONC. FOR CONTROL DEVELOPMENT GUIDANCE
● DEFINE DECISION CRITERIA FOR PRIORITIZING SOURCES, PROBLEMS
● DEFINE EMISSION GOALS
● PRIORITIZE POLLUTANTS
● NONPOLLUTANT IMPACT GOALS
● BIOASSAY CRITERIA
ENVIRONMENTAL ENGINEERING
ENVIRONMENTAL SCIENCES
ENVIRONMENTAL SCIENCES TECHNOLOGY TRANSFER
ENVIRONMENTAL ENGRG TECHNOLOGY TRANSFER
ENVIRONMENTAL SCIENCES R&D
● HEALTH/ECOLOGICAL EFFECTS RESEARCH
● TRANSPORT/TRANSFORMATION RESEARCH
MEDIA DEGRADATION AND HEALTH/ECOLOGICAL IMPACTS ANALYSIS
● AIR, WATER, AND LAND QUALITY
● INCREASED SICKNESS AND DEATHS
● ECOLOGY-RELATED EFFECTS
● MATERIAL-RELATED EFFECTS
OUTPUTS:
● QUANTIFIED EFFECTS ALTERNATIVES

Figure C-1. Environmental Assessment/Control Technology Development Diagram(97)

TABLE C-2. MEG CHART FOR NAPHTHALENE

NAPHTHALENE

EMISSION LEVEL GOALS

	I. Based on Best Technology		II. Based on Ambient Factors				
	A. Existing Standards	B. Developing Technology	A. Minimum Acute Toxicity Effluent		B. Ambient Level Goal*		C. Elimination of Discharge
	NSPS, BPT, BAT	Engineering Estimates (R&D Goals)	Based on Health Effects	Based on Ecological Effects	Based on Health Effects	Based on Ecological Effects	Natural Background*
Air, $\mu g/m^3$ (ppm Vol)			5.0E4 (10)		119 (0.02)		3.8-11.2†
Water, $\mu g/l$ (ppm Wt)			7.5E5	1.0E2	690	50	
Land, $\mu g/g$ (ppm Wt)			1.5E3	2.0E-1	1.38	0.1	

*To be multiplied by dilution factor

AMBIENT LEVEL GOALS

	I. Current or Proposed Ambient Standards or Criteria		II. Toxicity Based Estimated Permissible Concentration		III. Zero Threshold Pollutants Estimated Permissible Concentration
	A. Based on Health Effects	B. Based on Ecological Effects	A. Based on Health Effects	B. Based on Ecological Effects	Based on Health Effects
Air, $\mu g/m^3$ (ppm Vol)			119 (0.02)		142
Water, $\mu g/l$ (ppm Wt)			690	50	2,130
Land, $\mu g/g$ (ppm Wt)			1.38	0.1	4.26

†Reported for urban atmosphere. No rural concentration is reported.

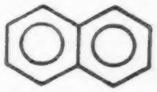
TABLE C-3. MEG BACKGROUND INFORMATION SUMMARY FOR NAPHTHALENE

CATEGORY: 21

WLN: L66J

NAPHTHALENE: $C_{10}H_8$ (moth flakes, naphthalin, naphthaline, naphthene, tar camphor, white tar).
Colorless monoclinic crystals, aromatic odor.

STRUCTURE:



PROPERTIES:

Molecular wt: 128.18 mp: 80.55, bp: 218, 87.5^{10}; d: 1.0253^{20}, 0.9625_4^{1000}; vap. press: 1 mm at 52.6° C; vap.d: 4.42; very low solubility in water; solubility may be enhanced by surfacant impurities in water (ref. 58).

NATURAL OCCURRENCE, CHARACTERISTICS, ASSOCIATED COMPOUNDS:

Naphthalene is among the lower molecular weight polycyclic hydrocarbons comprising the volatile portion of the benzene-soluble fraction of coal tar (ref. 4). Concentrations of 3.8 to 11.2 $\mu g/m^3$ in urban air are reported (ref. 1). Naphthalene is associated with particulate polycyclic aromatic hydrocarbons, PPAH (ref. 71). The following concentrations of PPAH have been estimated or reported: Air (urban environment in winter in seven selected U.S. cities): 21.6 ng/m^3 - 146 ng/m^3 (ref. 71); groundwater and surface treated water: 0.001 $\mu g/\ell$ - 0.025 $\mu g/\ell$ (ref. 58); upper layer of Earth's crust: 100 $\mu g/kg$ - 1,000 $\mu g/kg$ (ref. 58).

TOXIC PROPERTIES, HEALTH EFFECTS:

LD_{50} (oral, rat): 1,780 mg/kg.
Naphthalene may cause irritation in concentrations of 15 ppm, and serious damage to eyes may result from continuous exposure (ref. 4).

Naphthalene may be present in soot, coal tar, and pitch, which are known to be carcinogenic to man. Carcinogenic polycyclic aromatic hydrocarbons may induce tumors at the site of application (ref. 59). Naphthalene is included in the NIOSH Suspected Carcinogen List. The EPA/NIOSH ordering number is 4101. The lowest dose to induce an oncogenic response is reported as 3,500 mg/kg. The adjusted ordering number is 1.17. Naphthalene is considered inactive as a carcinogen (ref. 59).

Naphthalene has been rated as moderately toxic to aquatic organisms. The 96-hour TLm is reported as 1-10 ppm (ref. 2). Naphthalene in concentrations of 1 mg/ℓ may cause tainting of fish flesh (refs. 28, 69).

REGULATORY ACTIONS, STANDARDS, CRITERIA, RECOGNITION, CANDIDATE STATUS FOR SPECIFIC REGULATION:

Naphthalene appears on EPA Consent Decree List with an assigned priority of 2.
TLV: 50 mg/m^3 (10 ppm)
TLV for coal-tar pitch: 0.2 mg/m^3 [The specification includes naphthalene, anthracene, acridine, phenanthrene, and fluorene collectively. The purpose of the TLV is to minimize concentrations of higher weight polycyclic hydrocarbons which are carcinogenic (ref. 4).]

MINIMUM ACUTE TOXICITY CONCENTRATIONS:

Air, Health: 5.0×10^4 $\mu g/m^3$ (10 ppm)
Water, Health: $15 \times 5.0 \times 10^4 = 7.5 \times 10^5$ $\mu g/\ell$
Land, Health: $0.002 \times 7.5 \times 10^5 = 1.5 \times 10^3$ $\mu g/g$

Air, Ecology:
Water, Ecology: $100 \times 1 = 100$ $\mu g/\ell$
Land, Ecology: $0.002 \times 100 = 0.2$ $\mu g/g$

ESTIMATED PERMISSIBLE CONCENTRATIONS:

$EPC_{AH1} = 10^3 \times 50/420 = 119$ $\mu g/m^3$
$EPC_{AH1a} = 10/420 = 0.02$ ppm
$EPC_{WH1} = 15 \times 119 = 1{,}785$ $\mu g/\ell$
$EPC_{WH2} = 13.8 \times 50 = 690$ $\mu g/\ell$
$EPC_{LH} = 0.002 \times 690 = 1.38$ $\mu g/g$
$EPC_{AC2} = 10^3/(6 \times 1.17) = 142$ $\mu g/m^3$
$EPC_{WC} = 15 \times 142 = 2{,}130$ $\mu g/\ell$
$EPC_{LC} = 0.002 \times 2{,}130 = 4.26$ $\mu g/g$

$EPC_{WE1} = 50 \times 1 = 50$ $\mu g/\ell$
$EPC_{WE2} = 1{,}000$ $\mu g/\ell$ (to prevent tainting)
$EPC_{LE} = 0.002 \times 50 = 0.1$ $\mu g/g$

TABLE C-4. SAM/IA SUMMARY SHEET

1. SOURCE AND APPLICABLE CONTROL OPTIONS

2. PROCESS THROUGHPUT OR CAPACITY

3. USE THIS SPACE TO SKETCH A BLOCK DIAGRAM OF THE SOURCE AND CONTROL ITEMS SHOWING ALL EFFLUENT STREAMS. INDICATE EACH STREAM WITH A CIRCLED NUMBER USING 101-199 FOR GASEOUS STREAMS, 201-299 FOR LIQUID STREAMS, AND 301-399 FOR SOLID WASTE STREAMS.

4. LIST AND DESCRIBE GASEOUS EFFLUENT STREAMS USING RELEVANT NUMBERS FROM STEP 3.

101 ________________

102 ________________

103 ________________

104 ________________

105 ________________

106 ________________

107 ________________

5. LIST AND DESCRIBE LIQUID EFFLUENT STREAMS USING RELEVANT NUMBERS FROM STEP 3.

201 ________________

202 ________________

203 ________________

204 ________________

205 ________________

206 ________________

6. LIST AND DESCRIBE SOLID WASTE EFFLUENT STREAMS USING RELEVANT NUMBERS FROM STEP 3.

301 ________________

302 ________________

303 ________________

304 ________________

305 ________________

306 ________________

7. IF YOU ARE PERFORMING A LEVEL 1 ASSESSMENT, COMPLETE THE IA02-LEVEL 1 FORM FOR EACH EFFLUENT STREAM LISTED ABOVE. IF YOU ARE PERFORMING A LEVEL 2 ASSESSMENT, COMPLETE THE IA02-LEVEL 2 FORM FOR EACH EFFLUENT STREAM LISTED ABOVE.

(continued)

TABLE C-4. CONTINUED

8. LIST SUMS FROM LINE 7, FORMS IA02, IN TABLE BELOW

DEGREE OF HAZARD AND TOXIC UNIT DISCHARGE RATES BY EFFLUENT STREAM

GASEOUS					LIQUID					SOLID WASTE				
STREAM CODE	DEGREE OF HAZARD		TOXIC UNIT DISCHARGE RATES		STREAM CODE	DEGREE OF HAZARD		TOXIC UNIT DISCHARGE RATES		STREAM CODE	DEGREE OF HAZARD		TOXIC UNIT DISCHARGE RATES	
	HEALTH BASED	ECOL BASED	HEALTH BASED	ECOL. BASED		HEALTH BASED	ECOL. BASED	HEALTH BASED	ECOL. BASED		HEALTH BASED	ECOL. BASED	HEALTH BASED	ECOL. BASED
	—	—	(m^3/sec)			—	—	(l/sec)			—	—	(g/sec)	
A	B	C	D	E	F	G	H	I	J	K	L	M	N	O

9. SUM SEPARATELY GASEOUS, LIQUID AND SOLID WASTE STREAM DEGREES OF HAZARD FROM TABLE AT LINE 8 (I.E., SUM COLUMNS)

TOTAL DEGREE OF HAZARD

	HEALTH-BASED	ECOLOGICAL-BASED
GASEOUS	(Σ COL. B) 9A ____________	(Σ COL. C) 9A′ ____________
LIQUID	(Σ COL. G) 9B ____________	(Σ COL. H) 9B′ ____________
SOLID WASTE	(Σ COL. L) 9C ____________	(Σ COL. M) 9C′ ____________

10. SUM SEPARATELY GASEOUS, LIQUID AND SOLID WASTE STREAM TOXIC UNIT DISCHARGE RATES FROM TABLE AT LINE 8 (I.E., SUM COLUMNS)

TOTAL TOXIC UNIT DISCHARGE RATES

	HEALTH-BASED	ECOLOGICAL-BASED
GASEOUS (m^3/sec)	(Σ COL. D) 10A ____________	(Σ COL. E) 10A′ ____________
LIQUID (l/sec)	(Σ COL. I) 10B ____________	(Σ COL. J) 10B′ ____________
SOLID WASTE (g/sec)	(Σ COL. N) 10C ____________	(Σ COL. O) 10C′ ____________

11. NUMBER OF EFFLUENT STREAMS

GASEOUS 11A ______________________________

LIQUID 11B ______________________________

SOLID WASTE 11C ______________________________

12. LIST POLLUTANT SPECIES KNOWN OR SUSPECTED TO BE EMITTED FOR WHICH A MATE IS NOT AVAILABLE.